Shoulder to Shoulder

PrimeWest Energy Trust

Annual Report 2003

Profile

PrimeWest Energy Trust is a Calgary-based conventional oil and natural gas royalty trust that actively acquires, develops, produces and sells natural gas, crude oil, and natural gas liquids to generate monthly cash distributions for Unitholders. The Trust was formed in 1996 and with its 67% natural gas weighting, is one of North America's largest natural gas weighted energy trusts.

PrimeWest's assets are focused in the Western Canada Sedimentary Basin. The Trust's production is primarily derived from a suite of 15 core assets, which produced an average of 33,316 barrels of oil equivalent (BOE) per day in 2003.

PrimeWest's objective is to maximize total return to Unitholders, in the form of cash distributions and change in unit price. Our plan to achieve this includes executing our strategies for asset management and growth, financial management and corporate governance. We will continue to develop our core properties, pursue acquisitions that emphasize value creation, exercise disciplined financial management which broadens access to capital while minimizing risk to Unitholders, and comply with corporate governance requirements to protect the interests of all stakeholders.

Trust units of PrimeWest are traded on the Toronto Stock Exchange (TSX) under the symbol "PWI.UN" and on the New York Stock Exchange under the symbol "PWI". Exchangeable shares of PrimeWest Energy Inc. are listed on the TSX and trade under the symbol "PWX".

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Notice of Meeting

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In Dialogue with Investors

The Top 10 Questions Investors Ask About PrimeWest Energy Trust

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Landowner
Crossfield, Alberta

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President and CEO
PrimeWest
Energy Trust

Harold Milavsky
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We take this opportunity to respond to some of the key questions that investors have about PrimeWest and how we manage our business.

These questions are central to our vision, our business model and the strategies we employ to create value. Equally important, they address the discipline we bring to our operations that helps maximize margins from the sale of our oil and natural gas production. The answers to these questions will introduce you to some of PrimeWest's more than 100 people. They are representative of the technical, financial and administrative strength behind our name and our assets.

Photo from far left:
Ron Ambrozy, Dennis Feuchuk,
Don Garner, Tim Granger.

Don Garner
President and Chief Executive Officer

Don Garner joined PrimeWest in June 2001 and has overall responsibility for leading and overseeing the business direction of the Trust. He has more than 25 years of experience in the oil and natural gas industry. He was President and Chief Operating Officer of Northstar Energy Corporation from 1998 to 2001. Prior to that Mr. Garner spent a significant portion of his career at Imperial Oil Limited in various capacities, including executive responsibility for the Oilsands Business Unit. Mr. Garner is an engineering graduate of the University of Saskatchewan.

Dennis Feuchuk
Vice-President, Finance and Chief Financial Officer

Dennis Feuchuk joined PrimeWest in October 2001 and is responsible for the general financial operations of PrimeWest including tax and accounting matters, as well as Information Systems. Mr. Feuchuk has over 30 years of experience in finance, accounting, audit and income tax in the oil and natural gas industry. He was Vice President, Controller of Gulf Canada Resources from 1995 to 2001. Mr. Feuchuk also was Vice President and Treasurer of Athabasca Oil Sands Trust from inception in 1995 to 2001. Mr. Feuchuk has a Bachelor of Business Management from Ryerson University and has completed the Richard Ivey School of Business Executive Development Program and is a Certified Management Accountant.

Tim Granger
Chief Operating Officer

Tim Granger joined PrimeWest in June 1999 and has overall responsibility for oil and natural gas development activities and production at PrimeWest. Mr. Granger has more than 24 years of experience in development, production, operations and asset management. From 1996 to 1999, Mr. Granger held various managerial positions at Pogo Canada Ltd. and Petro-Canada, including production engineering and upstream and corporate information technology. Prior to 1996, Mr. Granger held various engineering and management positions at Amerada Hess, Dynex Petroleum, Canterra Energy and Dome Petroleum. Mr. Granger is an engineering graduate of Carleton University.

Ron Ambrozy
Vice President, Business Development

Ron Ambrozy has over 29 years of experience in the oil and natural gas industry. Prior to joining PrimeWest in 1997, Mr. Ambrozy held progressively more senior positions with Gulf Canada Resources Limited, including manager of Gulf's asset management group. He has led the evaluation of properties and completion of transactions worth more than $3 billion over the past 15 years. For the last five years, Mr. Ambrozy has been actively involved with the Petroleum Acquisition and Divestment Association (PADA), an organization of oil and natural gas people involved in A&D activity, and is currently President of that organization. Mr. Ambrozy is an engineering graduate from the University of Manitoba.

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Bruce Dowell
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1. *What is PrimeWest's strategy for offsetting the natural decline of its base production?*

A combination of development strategies and accretive acquisitions.

Like all oil and natural gas producing companies, PrimeWest's suite of assets are depleting. As oil and natural gas are produced from a reservoir, the reserves are depleted which leads to a decline in the production rate. The rates at which production declines will vary from reservoir to reservoir. For PrimeWest's mix of assets, the natural decline of our base production is currently approximately 20% per year.

PrimeWest strives to offset the base production decline by drilling new wells, implementing enhanced recovery methodologies and making property acquisitions. PrimeWest's development team is responsible for identifying the prospects for drilling and the application of optimization techniques to maximize production from our existing asset base. However, few royalty trusts can offset base production decline through development opportunities alone. Property acquisitions are an important element in the royalty trust business in terms of adding production and providing a continuous supply of future development prospects.

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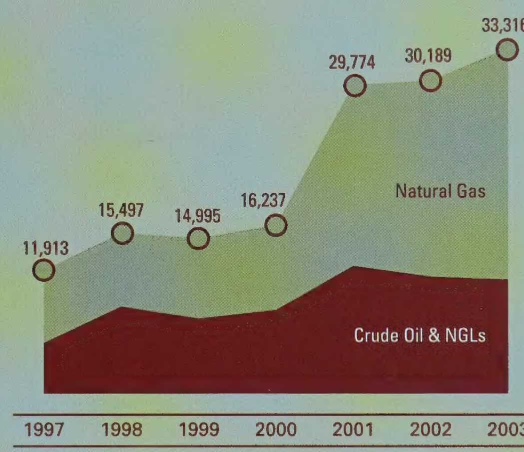
Business Development

The Business Development team at PrimeWest is primarily responsible for identifying, reviewing and evaluating acquisition opportunities for the Trust. The members of PrimeWest's Business Development Team shown in the photo on the opposite page are (from left) Zeno Bereznicki, Sr. Engineer; Peter Churcher, Manager; Ron Ambrozy, Vice President; and Pat McKeown, Engineering Technologist.

In selecting new assets for acquisition, we adhere to strict economic and financial criteria. Our business development team scrutinizes each potential transaction to ensure it will be accretive to net asset value (NAV) per unit and meet specific rate of return targets. Our acquisition focus is on expanding our existing core areas, or building new core areas where we can develop a competitive advantage.



Average Daily Production
(BOE/day)

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Landowner
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2. As evaluated under National Instrument 51-101, how did PrimeWest's reserves change in 2003 compared to 2002?

National Instrument (NI) 51-101 is the new disclosure standard implemented by the Canadian Securities Administrators for all Canadian public companies that report reserves after September 30, 2003. This replaces the previous standards as established by National Policy 2B.

The biggest improvements that NI 51-101 brings are the quantitative guidelines to assist the independent reserves engineers in their estimates of recoverable reserves. For Proved reserves, the engineers must now have at least a 90% confidence that the volumes ultimately recovered by the reporting company would equal or exceed the engineering estimate. For Proved and Probable reserves, the confidence level must be at least 50%. From a valuation standpoint, the more stringent requirements of NI 51-101 stipulate that 100% of the Probable reserve value should be included, as opposed to risking the Probable value by 50% to account for potential risk with the estimates, as was commonly done under the term 'Established reserves' before NI 51-101.

The other significant change under NI 51-101 is the requirement to disclose reserves on a Net basis. Net reserves include reserve volumes in which the reporting company has a beneficial interest, including royalty interests, minus the volumes attributable to royalty

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Asset Development

The primary responsibility of the Development Team is to maximize the value of the Trust's asset portfolio through value-added capital investment. This includes all aspects of development opportunities from drilling to reservoir optimization and facility enhancements. The goal is to add reserves and production volumes and to control or reduce operating costs.

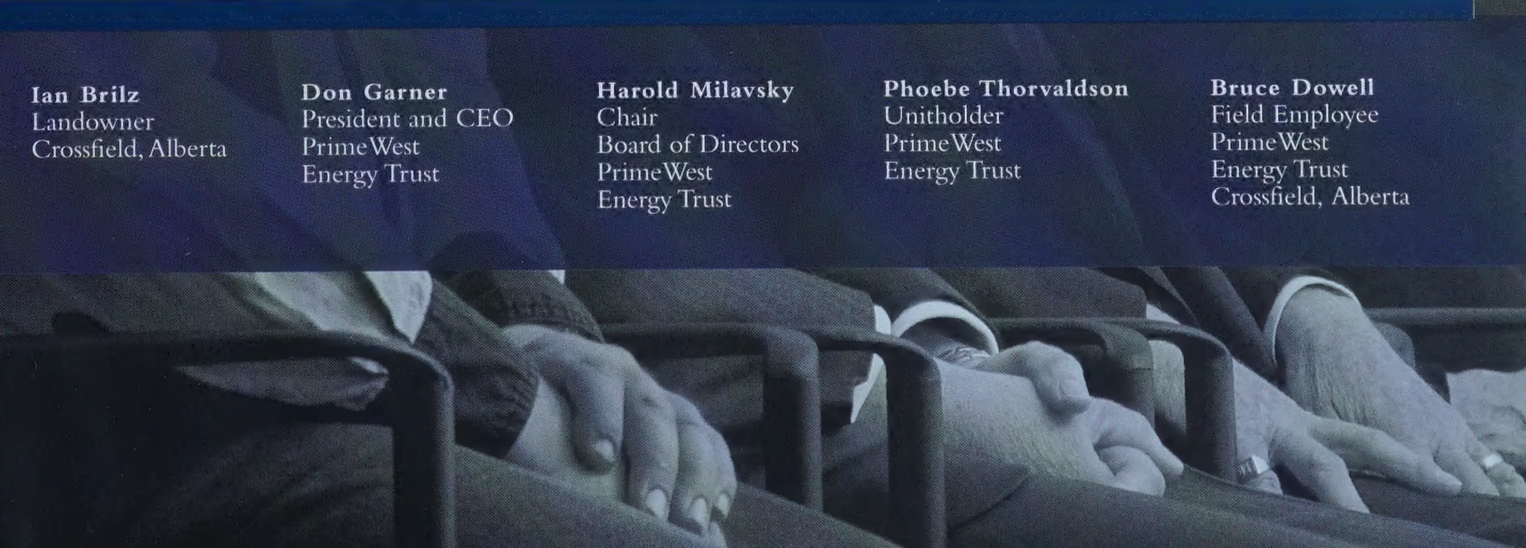
The team is led by Tony Van Winkoop, General Manager, Development, (standing left) and includes the three business unit teams plus the technical services group. Seated left is Leo Nolte, Drilling & Completions Engineer; John Duerksen, Operations Engineer (standing right); and James Manuel, Drilling & Completions Engineer (seated right).

expense. For 2003, it is expected the majority of the reporting companies will disclose reserves based on both Company Interest and Net. (See discussion under "Reserves and Production" on pages 37-41 of the annual report.)

PrimeWest's 2003 Net Proved plus Probable reserves increased 1.5% compared to 2002 from 84.5 mmBOE as at December 31, 2002 on an Established basis to 85.8 mmBOE as at December 31, 2003 under NI 51-101. Similarly, the Trust's Company Interest Proved plus Probable reserves increased from 104.4 mmBOE at December 31, 2002 to 106.8 mmBOE at December 31, 2003, an increase of 2.3%.

106.8 mmBOE

Company Interest Proved plus Probable (P+P) reserves as at December 31, 2003, up from 104.4 mmBOE Company Interest Established reserves as at December 31, 2002.



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3. *Why is it in the interests of Canadian Unitholders to consider participation in the DRIP, PREP or OTUPP?*

It's simple.

The DRIP, PREP and OTUPP are abbreviations for the three programs we offer to current Canadian Unitholders to expand their investment in PrimeWest in a cost-effective way, or to enhance the cash yield on their monthly distributions.

The DRIP (Distribution Reinvestment Plan) allows current Canadian Unitholders to reinvest their distributions to purchase additional units of PrimeWest at a 5% discount to market price, and without incurring any brokerage fees. The issue price of the units is based on the volume weighted average unit price before the distribution date, less a 5% discount.

Under the OTUPP (Optional Trust Unit Purchase Plan), existing Unitholders can elect to purchase additional units of PrimeWest at the same 5% discounted volume weighted average unit price to a maximum of $100,000 annually. The number of units available under the OTUPP is limited to 2% of the number of units outstanding at the beginning of the year.

The PREP, or Premium Distribution Plan, allows participating Unitholders who receive cash for their monthly distribution to receive a cash distribution of up to 102% of the base distribution amount.

All Canadian Unitholders should consider participating in these programs, as they are designed to produce a win-win situation for both PrimeWest and its Unitholders. These

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Investor Relations

George Kesteven, Manager of Investor Relations (right) and Cindy Gray, Investor Relations Advisor (left) are responsible for all facets of PrimeWest's communications. One of PrimeWest's ongoing challenges is providing information to its more than 64,000 Unitholders about the Canadian energy royalty trust structure and how it differs from a conventional business model.

plans allow PrimeWest to receive regular equity injections without incurring any pricing discount that is typical in an equity offering. The 5% discount offered to Unitholders offsets the brokerage fees that must be paid in an equity offering.

The cost of complying with securities regulations in the U.S. prohibits PrimeWest from being able to offer the PREP or OTUPP components of these investment plans to U.S. Unitholders. However, PrimeWest will continue to study the feasibility of offering the DRIP component to U.S. Unitholders. For further information regarding PrimeWest's DRIP plans, please see page 97 of this annual report.

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4. *What is the Reserve Life Index?*

The Reserve Life Index (RLI) is a measure that is often used to compare oil and natural gas trusts. The RLI determines the number of years a trust's current reserves will last, assuming that the current production rate remains the same throughout the assumed reserve life (which it would not because of natural decline). RLI is calculated by dividing total reserve volumes by the total annual production. This Index is easy to derive using public data and allows for quick comparison among trusts producing a similar product mix. However, it is not an indicator of remaining economic life because production decline results in the productive life being substantially longer.

Although it is generally felt that a longer RLI is better, this is not often true from an economic perspective. A trust can actually extract more value from its reserves by accelerating production and thereby shortening the RLI. The benefits of higher current production include higher immediate cash flow, lower unit operating costs and more rapid payout of investment, which in combination, support higher distributions to Unitholders. PrimeWest's current RLI of approximately 10 years, on a Company Interest Proved plus Probable basis, is close to average within the Canadian oil and natural gas royalty trust sector. We believe our current RLI provides us with a balanced mix of assets with faster payout and assets with considerably longer RLI that will stabilize production over many years.

It is important that RLI be used in combination with other benchmarks when comparing the attractiveness of an investment in a particular royalty trust.

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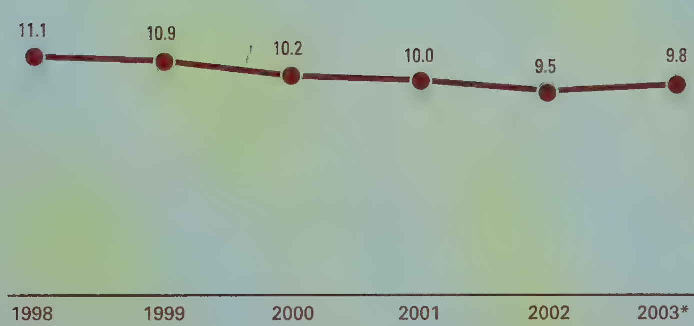
North Team

PrimeWest's Development Team is divided into 3 structured business units – the North, Central and South teams – each charged with managing the production, growth and development of core properties located within their respective regions of the Western Canada Sedimentary Basin. The North Team's properties have reserve lives ranging from 2.4 years (Dawson) to 18.8 years (Boundary Lake). Members of the North Team shown here are (from left): Ilze Piercey, Engineering Technologist; Tony Sacheli, Team Manager; Rick Howe, Sr. Exploitation Engineer; and Don Waters, Exploitation Engineer.



Reserve Life Index by Year

*2003 RLI based on Proved plus Probable reserves evaluated under NI 51-101, on a Company Interest basis. Prior years' RLI is based on Established reserves evaluated under NP 2B.

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Field Employee
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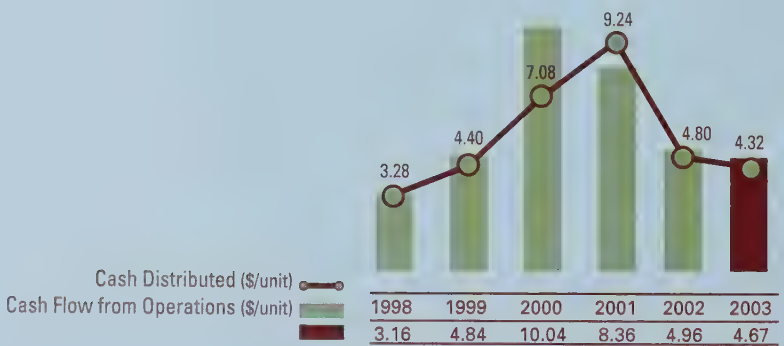
Crossfield, Alberta

5. *How will PrimeWest increase its longer-term sustainability by reinvesting more of its operating cash flow?*

Prior to 2003, PrimeWest historically distributed an average of 95% of its annual net operating cash flow to Unitholders. Our current goal is to maintain our distribution level within a band of 70-90% of annual cash flow. This is in keeping with the practice of the majority of the Canadian royalty trusts, which have opted to adopt a lower cash payout ratio to increase financial flexibility.

By retaining a greater proportion of cash flow than it has historically, PrimeWest can reduce the number of new equity issues or the need for debt financing, which should result in a lowering of its financing costs. It is less expensive for Unitholders if PrimeWest retains a dollar of internally generated cash flow than to raise new funds through borrowing or equity offerings.



Cash Distributed per Unit (upper figures) and Cash Flow per Unit (lower figures)

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Reinvesting Cash Flow into Development

In order to help fund development programs, as well as pay down debt, PrimeWest retains a portion of its cash flow each month, targeting an annual distribution payout ratio of approximately 70-90% of cash flow. Development teams, including the North Team shown here, seek out value-added development opportunities within PrimeWest's asset base.

How are you using the funds?

The funds that are retained can be used to reduce debt and contribute to funding the capital development program. Reducing debt leads to a healthy balance sheet, and for PrimeWest, can enable the Trust to pursue smaller acquisitions that can be paid for using debt. Funding the capital development program is very important for a trust to help offset natural decline in production and further the goal of extending the life of the trust.

90% Drilling Success Rate

PrimeWest drilled 105 wells in 2003, approximately half of which were in Caroline and Brant/Farrow.

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6. *How much of PrimeWest's cash flow is protected against the volatility in commodity prices?*

As part of its overall strategy of conservative financial management, PrimeWest utilizes a consistent commodity hedging approach. PrimeWest's risk management policy allows up to 70% of our net production (after royalties), to be hedged. The instruments we use include costless price collars, three-ways and forward-selling contracts.

PrimeWest's hedging program goals are to reduce commodity price volatility so as to increase cash flow stability as well as protect the economics of acquisitions. Stringent rules are put in place by the Board of Directors to manage the hedging program. As our objective in all cases is risk reduction, the hedging program can sometimes result in lower realized cash flow if actual commodity prices were higher than the prices being hedged. The hedging policy reflects a willingness to forfeit a portion of the pricing upside in return for protection against a significant downturn in prices.

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Marketing and Hedging

The Marketing Team is responsible for the daily sales administration of crude oil and natural gas, negotiating marketing contracts with buyers for the Trust's oil and natural gas, as well as risk management and hedging. The team is led by Glen McGinitie, Marketing Manager (far right) and includes Tracey Hyde, Marketing Representative, (seated right); Zena Holmberg, Marketing Administrator (standing left) and Roger Guerin, Senior Marketing Representative (seated left).

Because commodity prices were very high in 2003, both in historical terms and compared to prevailing forecasts, PrimeWest recorded hedging losses totaling $30.5 million for the year. This recorded loss is the calculation of how much more revenue PrimeWest would have generated had it not sold production on a hedged basis.

PrimeWest's risk management approach has benefitted Unitholders. Over the past three years from January 1, 2001 through December 31, 2003, PrimeWest has realized approximately $37.1 million in hedging gains.

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7. How will PrimeWest's natural gas weighting help maximize Unitholders' investment return in the longer-term?

PrimeWest's current production is weighted approximately 67% to natural gas with the remainder in crude oil and natural gas liquids. We believe our higher proportion of natural gas production will maximize our Unitholders' return in the future.

While both crude oil and natural gas prices are currently at historically high levels, natural gas is expected to have strong supply-demand fundamentals which can support prices in the long-term. While crude oil prices are subject to worldwide supply and demand and could fall due to increased supply, natural gas is a North American commodity whose value is determined by continental supply-demand dynamics. Natural gas demand is growing throughout North America, while deliverability from most of the continent's historical supply basins has peaked or is in decline. In general, this suggests continued upward pressure on natural gas prices.

The forward market for natural gas indicates relatively strong pricing through to 2007 and beyond. This puts PrimeWest in an excellent position with its higher natural gas weighting.

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Natural Gas Weighted Assets

One of the properties that the South Team will continue to focus on in 2004 is Brant/Farrow. Brant/Farrow is a shallow, natural gas producing area that offers ongoing potential development for PrimeWest. Members of the South Team shown here are (from left to right): Wayne Beatty, Sr. Exploitation Engineer; Shannon Ouellette, Team Manager; Greg Kaidannek, Geophysicist; and Wade Hansen, Geologist.

Natural Gas Pricing — Historical and Forward Strip
(Cdn$/mcf)
Historical AECO Natural Gas Price
Forward Strip at December 31, 2003

67%
of PrimeWest's
production is weighted to natural gas.

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8. How will PrimeWest manage to remain a low-cost producer in an environment of escalating costs for the sector?

Pursue operating efficiencies.

Operating costs across the energy sector trended up in 2003, led by higher power costs as a result of higher natural gas prices. Natural gas weighted companies like PrimeWest realized higher revenues, with the positive impact on our operating margins partially offset by the higher operating costs. In 2003, our operating costs were further impacted by a restructuring at the field level designed to increase operating efficiencies going forward.

Our 2003 operating costs were \$6.53/BOE, one of the lowest among the large cap energy royalty trusts in Canada.

By maintaining control of operations at approximately 80% of its properties, PrimeWest can exert more control over its costs and the timing and pace of development activities. When pursuing acquisitions, we strive to capture synergies from the acquired properties that we can attach to our existing asset bases. We do engage in heat rate swaps and power hedges at fixed prices to partially control electricity costs, which are a major component of our operating costs. For 2004, we are targeting operating costs of \$6.75/BOE.

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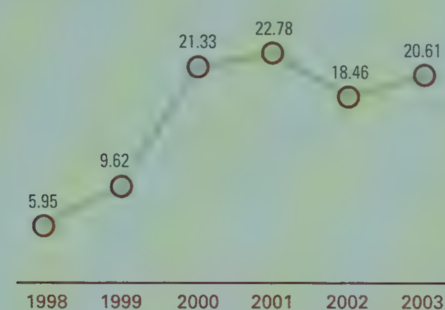
Controlling Operating Costs and Maximizing Margins

By expanding on existing core areas, PrimeWest can often lower operating costs and maximize operating margins by taking advantage of infrastructure and existing presence in the area. The Trust demonstrated this strategy by adding to its Caroline property in late 2002 and early 2003, reducing operating costs to $3.04/BOE in 2003 from approximately $6.02/BOE in 2002. Caroline is one of the properties managed by the Central Team, shown here (from left): Tim Lau, Geologist; Dwayne Timms, Sr. Joint Venture Representative; Ron Forth, Team Manager; and Janet Davies, Senior Exploitation Engineer.

Comparative 2003 Operating Costs
($/BOE)

PrimeWest Peer Group[1]
PrimeWest Energy Trust

[1]PrimeWest's peer group for this comparison consists of Canadian conventional energy royalty trusts that operated as a trust for calendar 2003, and whose production volumes were equivalent to 50% or more of PrimeWest's.



Operating Margin
($/BOE)

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9. By January of 2004, PrimeWest had paid out more cash per unit in monthly distributions than the $40 Initial Public Offering price in 1996. What is the relationship between the payout of distributions and a declining unit price over time?

The assets owned by an oil and natural gas trust like PrimeWest are depleted as the commodities are produced. Our business is based on the continuous conversion of these assets into cash flow, a portion of which is then distributed to our Unitholders.

As a result, the unit price declines as the assets are depleted and the underlying value of the trust is returned to the Unitholder in the form of monthly distributions.

How steeply the unit price and underlying value declines is impacted primarily by commodity prices, production rates, foreign exchange rates, costs, interest rates, and investor sentiment.

In attempting to offset this decline, a Trust may also acquire additional assets through corporate or asset acquisitions, and fund this growth by issuing new units. Acquisitions will be pursued by PrimeWest when they are accretive to the current Unitholders. Investment of capital into internal development opportunities is also used to partially offset natural decline.

Note:
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Cover photo (left to right): **Ian Brilz**, landowner in Crossfield, Alberta; **Don Garner**, PrimeWest's President and CEO; **Harold Milavsky**, Chair of PrimeWest's Board of Directors; **Phoebe Thorvaldson**, Unitholder; **Bruce Dowell**, PrimeWest employee, Crossfield natural gas plant.

Notice of Meeting

The Annual Meeting of the Unitholders of PrimeWest Energy Trust will be held on May 6, 2004 at 2:00 pm in Room Glen 206 at the Telus Convention Centre in Calgary, Alberta. All Unitholders and interested parties are invited to attend.

Financial Management

As VP Finance and CFO, Dennis Feuchuk oversees the financial management of PrimeWest. Part of successful financial management involves determining the optimal balance between cash distributions to Unitholders and reinvestment of cash for the long-term sustainability of PrimeWest.

It is important to remember that the Trust model is made up of more than unit price. It's about total return. Total return takes into account changes in unit price, cash distributed to Unitholders, and reinvested distributions. The Trust has delivered a total return averaging 30.4% per year over the last five years. From the Trust's inception to December 31, 2003 we've paid $771 million in distributions to Unitholders. Including the March 2004 distribution, PrimeWest will have paid $41.06 per unit versus the original IPO price of $40.00.

PrimeWest has delivered a 30% Annual Average

Compound Total Return over Five Years

Ian Brilz
Landowner
Crossfield, Alberta

Don Garner
President and CEO
PrimeWest
Energy Trust

Harold Milavsky
Chair
Board of Directors
PrimeWest
Energy Trust

Phoebe Thorvaldson
Unitholder
PrimeWest
Energy Trust

Bruce Dowell
Field Employee
PrimeWest
Energy Trust
Crossfield, Alberta

10. What can investors expect from PrimeWest in 2004 and why should I invest or remain an investor?

Long-Term Total Return to Unitholders

When an investor buys a PrimeWest unit, he or she has acquired an interest in a royalty trust that has a proven record of success since its inception in 1996. PrimeWest, as a major player in the Canadian oil and natural gas trust sector, has demonstrated consistent growth in total reserves and production over the years and is one of the highest natural gas-weighted producers among the large Canadian oil and natural gas trusts. On a one, three and five year basis, PrimeWest's total return has outperformed the major indices, which include S&P 500, TSX S&P Composite Index and the TSX Oil and Gas Producers Sub-Index.

In 2004, PrimeWest will continue striving to maximize Unitholder return. On the asset management side, PrimeWest will focus on successfully executing its $65-$90 million capital program to exploit opportunities that are within its current asset base. PrimeWest expects commodity prices to be volatile in 2004, which can lead to accretive acquisition opportunities to supplement its growth. A number of initiatives will be undertaken in our operating areas to control our operating costs and to maintain PrimeWest's position as being one of the lower cost, large capitalization royalty trusts.

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Strategic Direction

One of many responsibilities for Ryan Wong, Manager of Corporate Planning, is to ensure that PrimeWest follows its strategic direction and achieves corporate objectives. Ryan performs detailed financial analysis for PrimeWest, as well as budgeting, forecasting and presenting pertinent information to PrimeWest's Board of Directors.

Financially, PrimeWest will pursue a conservative management strategy by targeting debt at or below two times annual cash flow, while maintaining an active commodity hedging program to minimize the impact of price volatility.

Strong corporate governance will ensure that Unitholders' interests are looked after in a competitive business environment. It will also ensure that PrimeWest carries out its responsibility to the community in which it operates and is sensitive to environmental, health and safety issues.

Ian Brilz
Landowner
Crossfield, Alberta

Don Garner
President and CEO
PrimeWest
Energy Trust

Harold Milavsky
Chair
Board of Directors
PrimeWest
Energy Trust

Phoebe Thorvaldson
Unitholder
PrimeWest
Energy Trust

Bruce Dowell
Field Employee
PrimeWest
Energy Trust
Crossfield, Alberta

PrimeWest has achieved a competitive total return since inception.

Compound Total Return Comparisons (%)
Compound total return = unit price + distributions reinvested

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We stand *shoulder to shoulder* with one commitment

To maximize long-term total return.

We will achieve this by executing our strategies for asset management and growth, financial management and corporate governance.

Ian Brilz
Landowner
Crossfield, Alberta

Don Garner
President and CEO
PrimeWest
Energy Trust

Harold Milavsky
Chair
Board of Directors
PrimeWest
Energy Trust

Phoebe Thorvaldson
Unitholder
PrimeWest
Energy Trust

Bruce Dowell
Field Employee
PrimeWest
Energy Trust
Crossfield, Alberta

2003 Highlights

FINANCIAL HIGHLIGHTS

($ millions, except per BOE and per Trust unit amounts)	2003	2002
Net revenue	$ 329.9	$ 264.3
Per BOE	27.14	23.98
Cash flow from operations	216.6	170.9
Per BOE	17.82	15.51
Per trust unit	4.67	4.96
Royalty expense	101.9	56.5
Per BOE	8.38	5.13
Operating expense	79.4	60.8
Per BOE	6.53	5.52
General and administrative expenses – cash	14.5	11.3
Per BOE	1.20	1.02
General and administrative expenses – non-cash	14.4	6.1
Per BOE	1.19	0.55
Interest expense	15.1	10.8
Per BOE	1.24	0.98
Distributions to Unitholders	192.6	158.0
Per trust unit	4.32	4.80
Net debt	255.9	225.7
Per trust unit	5.07	5.75

OPERATING HIGHLIGHTS

	2003	2002
Average daily production		
Natural gas (mmcf/day)	134.1	113.5
Percentage of total production	67%	62%
Crude oil (bbls/day)	8,116	9,239
Percentage of total production	24%	31%
Natural gas liquids (bbls/day)	2,855	2,030
Percentage of total production	9%	7%
Total (BOE/day)	33,316	30,189
Average selling prices (Cdn$)[1]		
Natural gas ($/mcf)	$ 6.05	$ 4.55
Crude oil ($/bbl)	33.94	33.53
Natural gas liquids ($/bbl)	35.34	26.56
Total oil equivalent ($/BOE)[2]	$ 35.68	$ 29.16
Realized hedging gain (loss) included in prices above ($/BOE)	$ (2.51)	$ 2.55
Proved + Probable (P+P) Reserves (Company Interest)		
Crude oil (mmbbls)	22.9	24.5[3]
Natural gas liquids (mmbbls)	11.9	10.2[3]
Natural gas (Bcf)	432.2	418.5[3]
Total oil equivalent (mmBOE)	106.8	104.4[3]
Reserve Life Index (P+P)	9.8	9.5[3]

[1] Includes hedging gains/losses.
[2] Excludes sulphur.
[3] Represents Established reserves from PrimeWest's December 31, 2002 reserves report.

Management's Letter to Unitholders

Shoulder to shoulder. Our theme this year reflects the alignment of PrimeWest's goals and values with those of our stakeholders, including Unitholders, lenders, landowners, community residents, regulators and staff members. PrimeWest's goal is to maximize long-term total return to Unitholders through the combination of cash distributions and change in unit price. We intend to deliver by executing a plan that encompasses asset management and growth, financial management, and corporate governance.

PrimeWest will not pursue growth for growth's sake. We will grow – through acquisitions or development drilling – only when these activities increase net asset value per unit and meet specific rate of return targets. Following a key acquisition at Caroline early in the year, we refrained from further acquisitions in 2003 for the simple reason that asset prices were too high to allow us to add further value.

We believe our current size is advantageous, providing us operating efficiencies as well as the critical mass to participate in significant acquisition opportunities. At the same time, we willingly dispose of properties that have become non-core or that have fallen below our economic thresholds. Meanwhile, we continuously pursue new avenues to control costs, such as through our 2003 field-level restructuring. At $6.53/BOE, PrimeWest's 2003 operating costs were among the lowest of the large cap Canadian energy royalty trusts. These are examples of our strategy in action.

Total return is one of the best measures to benchmark a trust's performance, because it takes into account changes in the unit price as well as distributions. PrimeWest delivered a total return of 28% in 2003. Over the last five years, we have achieved a compound average total return of 30%.

Asset Management and Growth

Since inception, PrimeWest has focused on the conventional oil and natural gas plays of the Western Canada Sedimentary Basin. Within this focused area, we have a diversified, multi-zone suite of assets stretching from northeast B.C., across much of Alberta and down through southwest Saskatchewan. We believe this diversity reduces risks to overall corporate production and cash flow, while the core area focus allows us to capitalize on our existing technical knowledge.

PrimeWest's operations are conducted with the goal of adding value to the Trust, in support of current and future distributions. Within our core areas, we strive for high working interests and wherever possible, control over operations, which gives us authority over timing of projects and capital outlays. As a result, PrimeWest can manage its costs and identify and execute on development opportunities. We also continuously pursue field optimization in these core areas to maximize the value of our assets.

We have planned development programs to tap the upside opportunities at Caroline, Brant/Farrow, Valhalla and the Princess/Hays region acquired in early 2004. In 2004 we plan to drill 18-25 shallow natural gas wells at Brant/Farrow, 8-12 higher-impact natural gas wells at our recently augmented Caroline property, and 10 natural gas wells at Valhalla.

As we mentioned earlier, PrimeWest will not grow for growth's sake. We will undertake acquisition and development activities that add value. We will focus our expansion efforts on existing core areas, or create new ones. Our technical understanding of a prospective asset helps us identify unrecognized value.

The 2003 acquisition at Caroline, valued at $219.1 million, substantially increased our position at Caroline, giving us new production, large areas of undeveloped land and strategic infrastructure which allows us to control costs. At Grand Forks, one of our more mature assets, PrimeWest has maintained the net asset value at approximately the same level for five years, while generating a cumulative $100 million in cash flow. These successes demonstrate our ability to acquire wisely and maximize the value of our assets.

Early in 2004, PrimeWest entered into an agreement to acquire Seventh Energy Ltd., a publicly traded junior oil and natural gas company. The acquisition of Seventh Energy Ltd. when completed, will represent an excellent fit with our strategy. The Company is natural gas focused; the assets offer upside potential; there is a significant undeveloped land base; and the transaction is accretive to 2004 cash flow, production and net asset value per unit. To protect the transaction economics, PrimeWest hedged approximately 70% of the natural gas production at an attractive price. As a result of our strong balance sheet, PrimeWest intends to pay the $42.6 million price tag in cash through its credit facility.

Reserves

Effective September 2003, Canadian Securities Administrators implemented National Instrument (NI) 51-101, a regulation designed to standardize how all oil and natural gas companies report their reserves. This change includes more rigorous definitions of Proved and Probable reserves and a greater level of disclosure.

PrimeWest's Reserve Life Index of 9.8 years on a Company Interest Proved plus Probable basis at year end 2003 was close to average compared to the Canadian oil and gas trust sector. In our pursuit of acquisitions we seek to maintain or increase our Reserve Life Index to provide longer-term sustainability to production and cash flows. Yet there are situations where Unitholders can benefit from shorter Reserve Life acquisitions or development. Excessive inventory of reserves is costly and a drain on resources in any industry. A shorter reserve life can provide greater short-term cash flow and, because of discount rates that are applied to future cash flows, a higher net asset value in the marketplace. Reducing inventory by producing it maximizes the dollar value of the reserves. This must of course be balanced against the risks of price volatility and the uncertainty of sustainable production volumes going forward.

From left to right:

Don Garner
President and CEO

Ron Ambrozy
VP Business Development

Tim Granger
Chief Operating Officer

Dennis Feuchuk
VP Finance and CFO

2003 Operating Results

PrimeWest's production is natural gas weighted, which supports our short and longer-term outlook for natural gas prices. Recent natural gas prices as well as longer-term forward strip prices support our decisions to acquire natural gas weighted assets and to focus our development capital primarily in natural gas producing regions. However, with our focus on adding value, we will continue to consider acquisitions of crude oil properties and strive to capitalize on those assets that could add value.

PrimeWest's continuing objective has been to improve the quality of its production in order to improve operating margins. Today, our production is of relatively high quality as measured by operating margin per barrel. However, we remain committed to continuously maximizing operating margins by maintaining a high quality of production and keeping operating costs under control. This is not easy. Increased power costs and other industry-wide factors impacted PrimeWest's operating costs during 2003, and we also initiated a field level restructuring which affected costs in the second quarter.

PrimeWest's 2003 development program of $104.5 million was our largest ever and included the drilling of 105 new wells. Successful drilling helped offset our natural decline rate of approximately 20% in 2003 and added 7.9 mmBOE of Company Interest Proved plus Probable reserves.

PrimeWest's average 2003 production of 33,316 BOE/day was in line with our revised target of 33,500 BOE/day. Our initial target of 36,000 BOE/day

was revised due to higher than expected production declines at Caroline, and watering out of wells at Dawson and Stowe. In addition, we deferred some development activity planned for 2003 and halted development plans at our Seal property that had failed to achieve appropriate results.

Financial Management

Development activities and acquisitions require capital in the form of additional equity or bank debt.

PrimeWest maintains a conservative debt to cash flow ratio, which positions us for counter-cyclical acquisitions when commodity prices fall. We currently have total borrowing capacity of $390 million, with unutilized credit of approximately $134 million at year end 2003. At year end, our ratio of net debt to trailing cash flow was 1.2 times.

In May 2003, we successfully diversified our debt portfolio with a private placement of U.S. secured notes totaling US$125 million. The notes have a coupon rate of 4.19%, a term of seven years and an average life of 5.5 years. The stronger Canadian dollar has worked to our advantage with respect to this debt, as we recorded a foreign exchange gain of $12.1 million in 2003. However, a strong Canadian dollar also has negative implications for PrimeWest, because commodity prices are determined in US dollars and then converted to Canadian currency. Therefore, a higher Canadian dollar results in lower realized revenues, which directly impacts cash flows and distributions.

We believe PrimeWest's capital structure represents a competitive advantage. Our New York Stock Exchange listing enables U.S. investors to trade PrimeWest trust units, and allows us to access equity markets in the U.S. Our size and track record help control the cost of new borrowings. In the U.S. our structure as a corporation facilitates tax reporting for our U.S. investors. Strong overall demand for PrimeWest units supports strong total returns to all Unitholders, including Canadian investors.

A key concern for certain energy trust investors has been the issue of unlimited liability. PrimeWest's assets are held in a corporation, which we believe prevents any flow-through to Unitholders of liabilities arising from third party actions. At the time of writing, several provincial governments are considering new legislation that would provide Unitholders the same legal protection afforded to holders of common stock.

Hedging

Hedging is an important risk reduction tool aimed at stabilizing cash flow and protecting distributions. Under our Risk Management policy, PrimeWest can hedge up to 70% of its net production volumes. It is inevitable that in any given year we will be reporting a gain or loss relative to actual market prices. At year end 2002, the Trust had a hedging gain of approximately $67 million on the previous two years. However, during 2003 we recorded an opportunity loss of $30.5 million from the year's hedging activities. This loss capped our revenues during a period when commodity prices increased above the hedged levels.

PrimeWest's Payout Ratio and Distributions

Many Canadian energy trusts have lowered their cash flow payout ratios. It is less expensive to investors to retain a dollar of internally-generated cash than it is to raise new funds through borrowing or equity offerings. On the other hand, maintaining strong distributions supports unit values, which underpins total returns and reduces the cost of new acquisitions. Cash management is a balancing act.

Historically, PrimeWest has paid out a very high percentage of its cash flow from operations. We have made a strategic decision to ease this ratio downward. Retained cash flow is used for asset maintenance, servicing of debt, and reinvestment in order to enhance production levels. Going forward, our goal will be to distribute 70-90% of annual cash flow. Nevertheless, significant capital expenditures and large acquisitions will continue to be funded through equity offerings and proceeds from our distribution reinvestment plans. In 2003 PrimeWest distributed 89% of cash flows.

Corporate Governance

PrimeWest's Board of Directors and management team remain committed to the highest standards of corporate governance. In 2003, we appointed Glen Russell and Jim Patek as independent directors. Within our proxy circular and on our website, PrimeWest provides complete disclosure of our governance system, and details our compliance with corporate governance rules and regulations imposed by the relevant exchanges and securities commissions. In anticipation of future corporate governance rules, we have assigned committee leadership to independent directors and work continues to ensure we are prepared for 2005 sign-off of internal controls under the Sarbanes-Oxley Act of 2002.

2004 Outlook and Plans

PrimeWest's 2004 capital development program is budgeted between $65 and $90 million and will focus on Caroline, Valhalla, Brant/Farrow and the Princess/Hays assets to be acquired in the Seventh Energy Ltd. acquisition. We expect average production of 30,000 BOE/day for the year with average operating costs of approximately $6.75/BOE of production. Any acquisitions would be funded separately from this budget.

I extend thanks to every member of PrimeWest's technical team, field staff, head office personnel and senior managers and executives. We all share the responsibility of implementing our strategy for maximizing long-term total return to Unitholders. Thanks to every one of you. I also extend thanks to each of PrimeWest's directors who contribute such sound advice and vigorous corporate governance.

Don Garner
President and Chief Executive Officer
March 11, 2004

Managing the Trust's Performance

	Asset Growth and Management	Financial Management
Strategy	• Remain focused on Canadian conventional oil and gas assets. • Seek control over operations with high working interests. • Pursue aggressive field optimization to maximize asset value. • Focus expansion efforts on existing core areas. • Be an opportunistic acquirer that uses the business cycles to make accretive acquisitions.	• Maintain a conservative debt to cash flow ratio. • Build diversification in the debt portfolio • Use hedging to reduce exposure to commodity price volatility. • Broaden reinvestment alternatives to Unitholders.
2003 Benchmarked Performance	**Pursue value-added acquisitions in existing core areas or create new core area** • Closed the $219.1 million acquisition of Caroline and Peace River Arch assets initiated late 2002. **Average 34,500-35,500 BOE/day of production** • Production averaged 33,316 BOE/day, below the target of 34,500-35,500 BOE/day due to unexpected production issues and weather related drilling delays. **Invest $70 to $100 million in development activities to add incremental production** • Executed $104.5 million of capital programs – adding 7.9 mmBOE of reserves at $14.29/BOE. **Operating expenses between $6.00-$6.50/BOE** • Operating cost of $6.53/BOE reflected significant increase in power and fuel costs. **Maintain or increase Reserve Life Index** • Maintained Reserve Life Index at 9.8 years at year end (based on Company Interest Proved plus Probable reserves.)	**Maintain debt to cash flow ratio of less than two times** • Net debt to cash flow ratio was 1.2 at year end. • Issued US$125 million, seven year note at 4.19% coupon rate to provide a natural hedge to our U.S. currency exposure. • Completed $235 million of equity issues. • Implemented a Premium DRIP program. **Reduce distribution volatility by price protecting up to 70% of production, net of royalties and development additions** • Remained active in commodity hedging to minimize price volatility. The program incurred a net loss of $30.5 million as actual prices exceeded hedge levels. Over the last three years, hedge gains have totaled $37.1 million.
2004 Objectives	• Average approximately 30,000 BOE/day production. • Target operating costs of approximately $6.75/BOE. • Invest between $65 and $90 million in development of core assets.	• Maintain net debt to cash flow multiple less than two times. • Distribute an average 70-90% of cash flow annually.

Corporate Governance

- Continue expansion of equity market access.
- Commit to a high standard of corporate governance.
- Assign committee leadership to independent directors.
- Ensure complete disclosure of governance system.
- Proactively manage environmental, health and safety issues.

Comply with existing corporate governance regulations of the Toronto Stock Exchange (TSX), New York Stock Exchange (NYSE) and Sarbanes-Oxley Act (SOX)

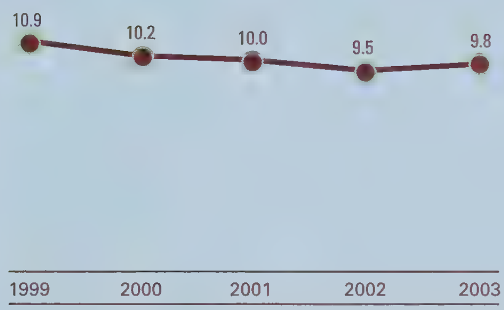
- Added two independent Board members.
- Complied with all 14 guidelines for corporate governance outlined by the TSX, and substantially all NYSE corporate governance guidelines, despite being exempt due to foreign private issuer status (details to be contained in our information circular).

Comply with existing and proposed rules and regulations concerning environment, health and safety

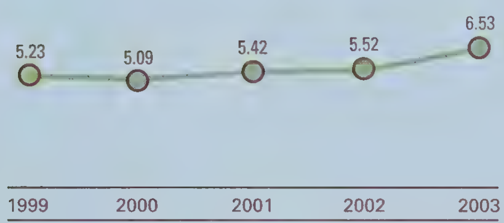
- Awarded Gold Champion Level status for participation in Voluntary Challenge Registry (VCR) Report for monitoring greenhouse gas emissions and energy use.
- Implemented an in-house competency certification program for all field operators in 2003 positioning PrimeWest to be in compliance with the proposed new 2004 Occupational Health and Safety regulations.

- **Continue full compliance with existing and proposed environmental, health and safety guidelines and regulations.**
- **Continue proactive implementation of corporate governance initiatives. Ensure PrimeWest is fully compliant with sign-off of SOX in 2005.**

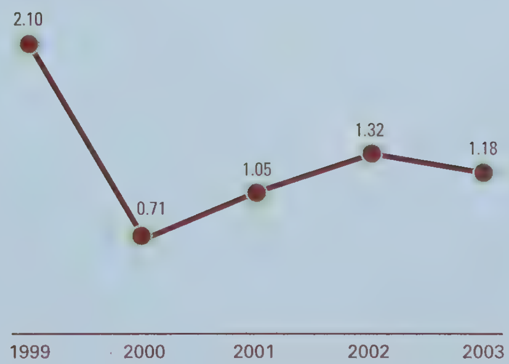
Cash Distributed
($/Unit)



Reserve Life Index by Year



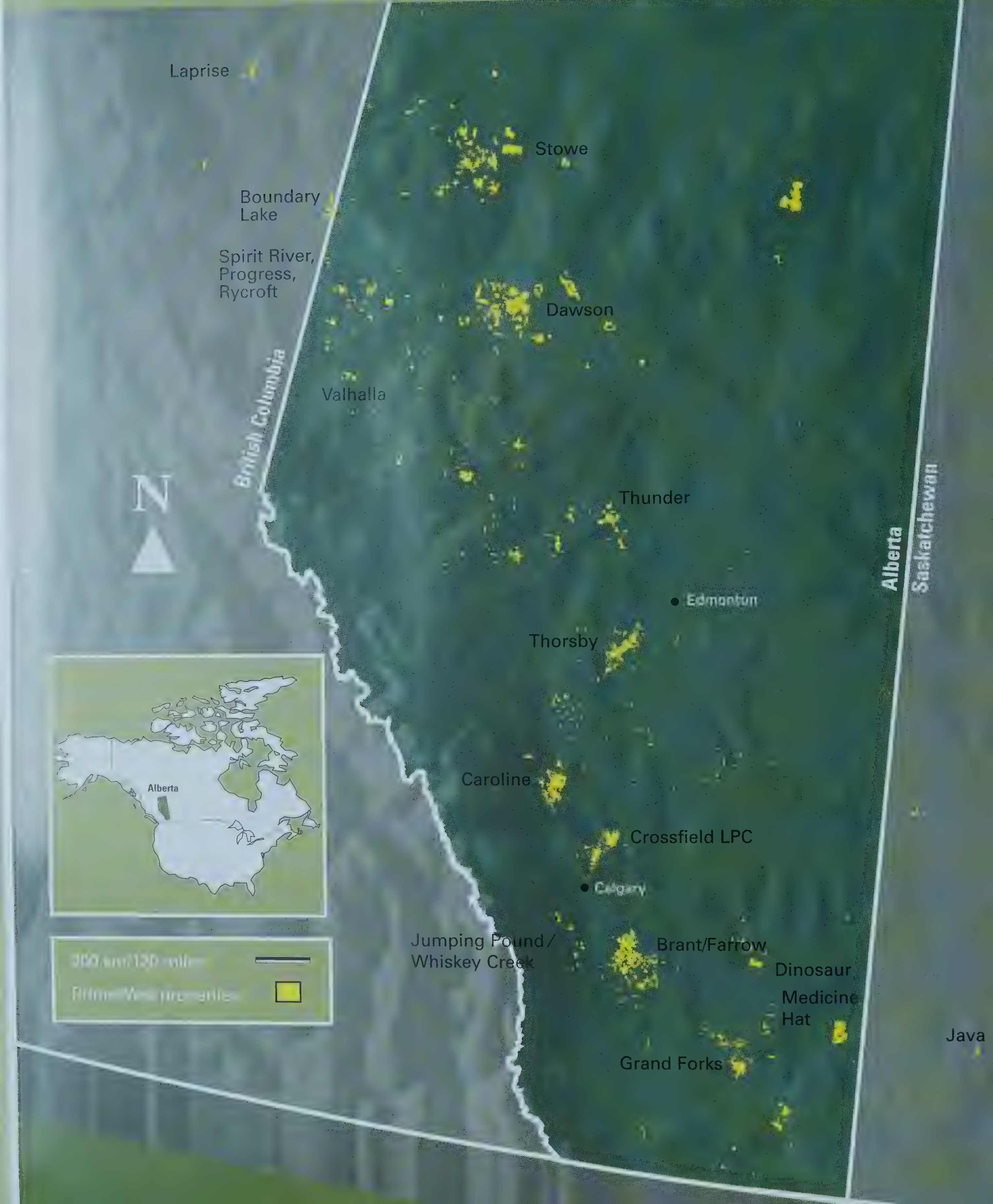
Operating Expenses
($/BOE)



Debt to Annual Cash Flow Multiple

Review of Operations and Assets

Review of Core Areas



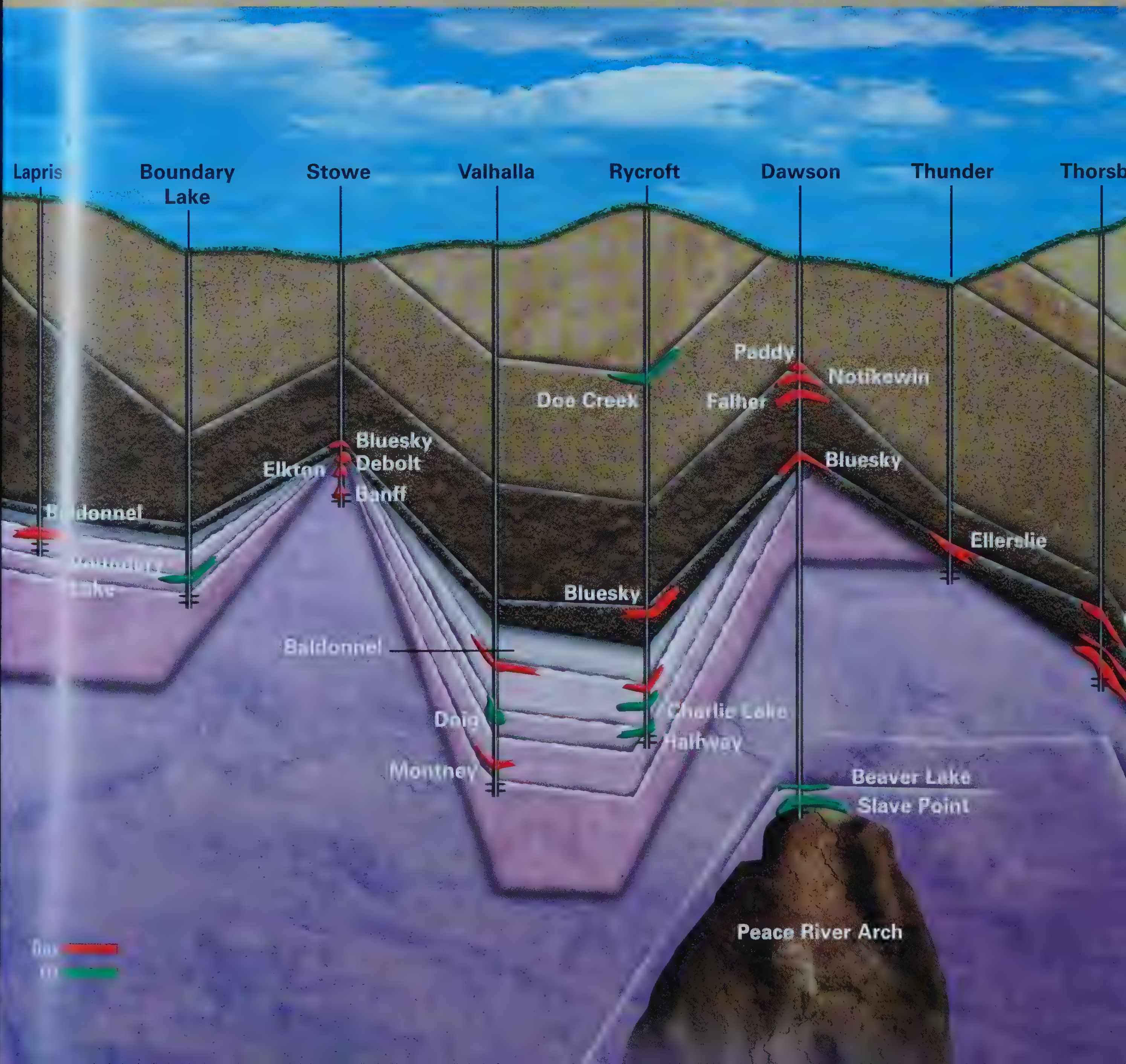
Major Holdings

	2003 Average Production (BOE/day)	2003 Operating Costs/BOE	Zones Targeted	2004 Capital Budget for Area	2004 Drilling Plans	Additional 2004 Capital Investments
North						
Laprise	1,643	$ 3.37	Baldonnel	$ 2MM	2 wells	3-D seismic
Boundary Lake	1,110	$ 7.76	Boundary Lake	$ 5MM	5 wells	Facilities waterflood optimization
Valhalla	2,159	$ 3.30	Montney, Doig, Gething	$ 12MM	10 wells	Continue plant upgrade
Spirit River, Progress, Rycroft	578	$ 9.93	Halfway, Charlie Lake, Doe Creek	$ 4MM	4 wells	
Dawson	2,467	$ 4.80	Bluesky, Notikewin, Paddy (Slave Point – Oil)	$ 5MM	9 wells	
Stowe	1,548	$ 7.75	Bluesky, Mississippian	$ 3MM	5 wells	Seismic
Central						
Thunder	428	$ 6.36	Ellerslie, Glauconite	$ 4MM	5 wells	Infrastructure and seismic
Caroline	5,154	$ 3.04	Cardium, Viking, Mannville, Elkton	$ 11MM	Up to 12 wells	Facility optimization
Crossfield/LPC	2,158	$ 10.92	Leduc, Nisku, Wabamun	$ 4MM	4 wells	
Thorsby	3,996	$ 4.75	Ellerslie, Glauconite	$ 4MM	2 wells	3-D seismic, well optimization and gathering system debottlenecking
South						
Jumping Pound/ Whiskey Creek	667	$ 8.06	Mississippian	$ 3MM		Tie-in and completion
Grand Forks	2,927	$ 12.81	Sawtooth, Arcs	$ 6MM	2 wells	Solution gas conservation
Brant/Farrow	1,813	$ 5.47	Belly River, Medicine Hat, Edmonton	$ 10MM	18-25 wells	3-D seismic shoot
Dinosaur/Medicine Hat	767	$ 3.77	Medicine Hat, Milk River, Second White Specks	$ 2MM	40+ wells/ recompletions	
Saskatchewan	545	$ 13.02	Cantuar, Roseray	$ 2MM	5 wells	

PrimeWest Operations: Geographically Diverse, Multi-Zone Potential, Opportunity-Rich

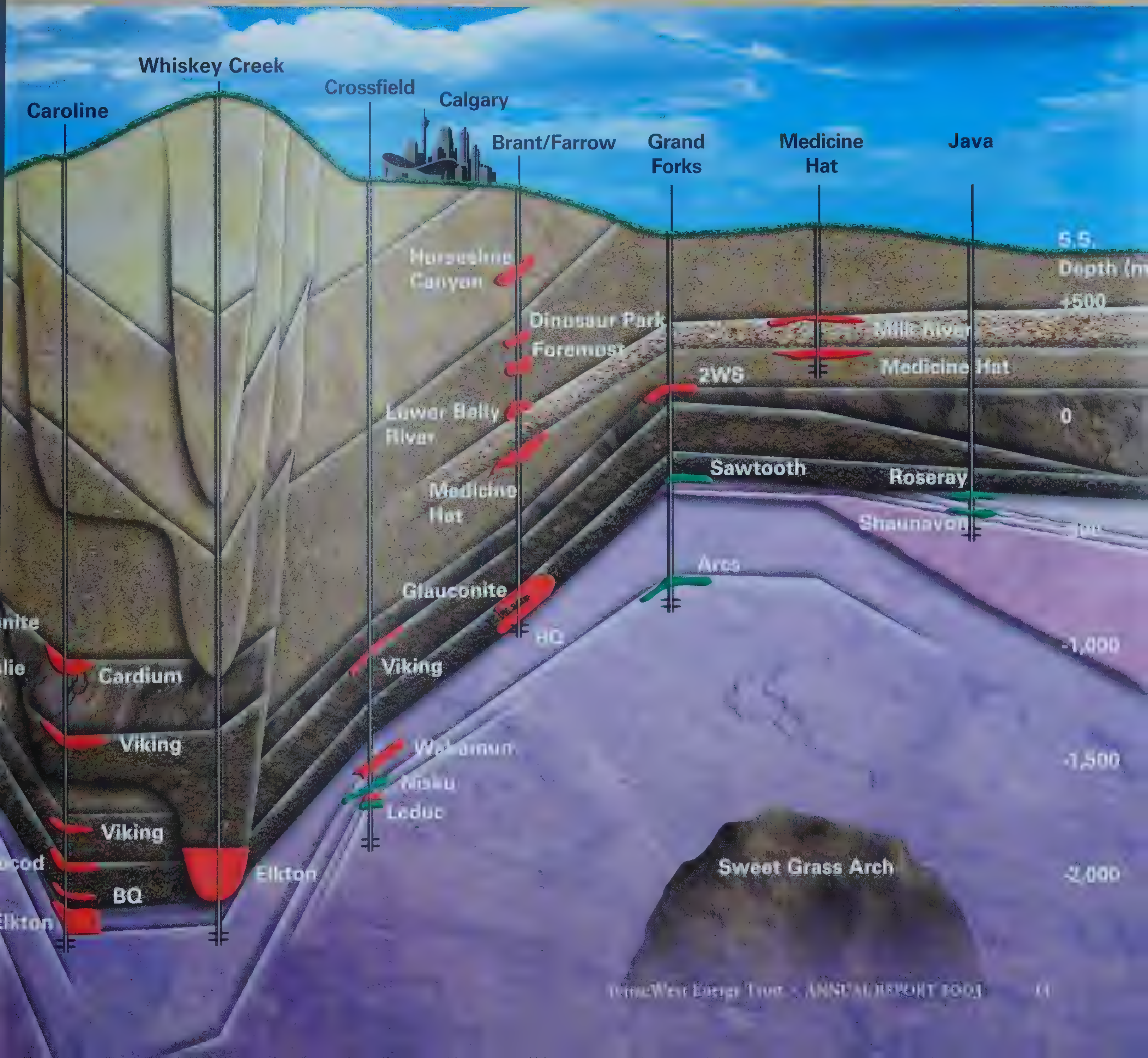
As demonstrated with the map on the facing page, PrimeWest's properties provide geographic diversity within the Western Canadian Sedimentary Basin. The Trust's properties range in location from Northeast B.C., across much of Alberta, and into Southwest Saskatchewan.

In addition to this geographical diversity, many of the core properties offer PrimeWest the potential for multi-zone production. Translated, this means there are several possible geological 'zones' from which oil or natural gas reserves can be produced. Occasionally, when a company drills for a particular



target zone, they may discover that other zones will provide additional potential for production. This can provide further risk mitigation in the drilling process.

Shown below is a geological cross-section running from northeast B.C. through Alberta and into Saskatchewan. Each of PrimeWest's core properties are illustrated by a representative well with oil and gas producing formations colored green and red respectively. PrimeWest's production portfolio is widely diversified and includes most of the major reservoirs and play types characteristic of the Western Canada Sedimentary Basin.



Operating Philosophy and 2003 Review

During 2003, PrimeWest Energy Trust's production averaged 33,316 BOE/day, consisting of 134.1 mmcf/day of natural gas and 10,971 bbls/day of crude oil and natural gas liquids. Capital investments totaled $104.5 million and included 105 new wells. The production decline rate before capital investment was approximately 20%. The Trust added significantly to its assets at Caroline in early 2003, but refrained from major acquisitions through the balance of the year in the face of high asset prices. Greater detail regarding the foregoing items can be found in the Operations Statistical Review beginning on page 22.

PrimeWest's operations are governed by several key principles. The most important is that all major activities, whether related to acquisitions, development, optimization or disposition, must be accretive to net asset value (NAV). PrimeWest's key operating principles are:

Capital Expenditures Must be Value-Accretive – Any proposed activity concerning acquisitions, development, optimization or disposition must enhance the Trust's net asset value (NAV) per unit and must meet specific rate of return targets.

Acquisition or development activities may have additional positive impacts on the Trust, such as the strengthening of core properties, expansion of our inventory of development projects, extension of the Reserve Life Index, optimization of the commodity weighting of the asset portfolio, and capture of cost reduction and operating synergies.

Geographical Diversity – PrimeWest's diversified asset base includes 15 core assets ranging from northeast B.C., through Alberta and into southwest Saskatchewan. No single asset dominates the Trust's production. An unforeseen event at any one property is unlikely to threaten overall corporate volumes. This helps to protect the Trust's cash flow.

Focused Growth Areas – PrimeWest's 2004 development program is concentrated at Valhalla, Brant/Farrow, Caroline and the new Princess/Hays area, expanded with an acquisition early in 2004. This enables the Trust to focus its capital spending and technical expertise in areas with maximum upside. It mitigates technical risks and facilitates rapid execution, therefore improving our chances of development success and maximizing near-term cash flow.

Commodity Focus – PrimeWest's production is 67% natural gas weighted. The Trust believes that North American supply-demand dynamics suggest strong natural gas prices for both the shorter and longer term.

About 60% of PrimeWest's 2003 oil volumes were light oil; the remainder were medium gravity. The average API of the Trust's produced crude oil in 2003 was 31 degrees.

Operational Excellence – Sound execution is crucial to meeting PrimeWest's value-adding objectives. Operational activities include drilling new wells, recompleting wells to target new productive zones, stimulating production from zones that are currently producing or optimizing facilities and infrastructure to maximize throughput. We also improve facilities to reduce operating costs or to attract volumes from other producers. These third-party volumes add to the Trust's cash flow. Control of infrastructure enables the Trust to determine the nature, pace and scope of development.

Farm-Outs – PrimeWest avoids high risk, exploratory drilling. We farm out high risk lands to exploration companies, as well as situations where we are unfamiliar with target geology or expiry of land rights is imminent. We maximize the value of these arrangements by including "back-in" provisions which enable the Trust to participate in development of any discoveries.

Control Operating Costs – To control its field operating costs the Trust employs techniques including active supervision of field staff, training staff to focus on the value-added aspects of field work, and focusing on preventative maintenance to maximize throughputs and minimize unplanned downtime. The goal is to support the operating margin and, hence, cash flow.

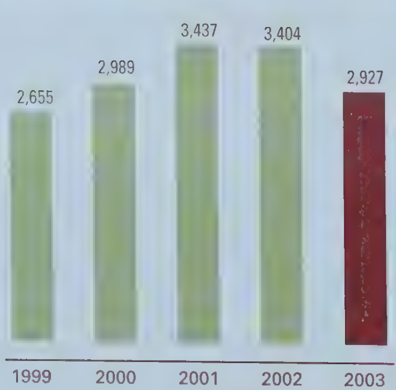
PrimeWest's operating costs increased in 2003, partly due to industry-wide factors such as high electricity costs and inflation of field services. In addition, PrimeWest booked 100% of the costs of a field-level restructuring to reduce staffing cost by 20%, and also expensed a new corrosion mitigation plan. Despite these additional costs, PrimeWest's operating expenses in 2003 were very close to our target for the year. The 2003 program positions PrimeWest to maintain its low operating cost structure in 2004.

These key principles will continue to govern PrimeWest's operations and acquisitions in 2004 and beyond. The following "Success in the Field" section demonstrates these principles in action at select PrimeWest properties.

Success at Grand Forks, Alberta.

Located in the Southern part of Alberta, Grand Forks is PrimeWest's fourth largest producing property. This medium/heavy oil region produced approximately 2,900 BOE/day in 2003.

A mature asset generating constant value for five years



Grand Forks Production (BOE/day)

PrimeWest's Grand Forks asset has maintained a constant value for five years – a result of our successful development. The asset has also generated cumulative cash flow totaling \$100 million to year end 2003 since its acquisition in 1998. Purchased as a counter-cyclical acquisition during a period of low commodity prices, Grand Forks has benefited Unitholders from both an acquisition price and a development standpoint.

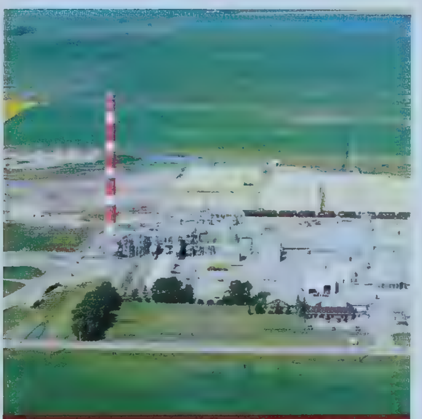
The property's oil production averaged 2,927 BOE/day in 2003. PrimeWest has invested a cumulative \$32 million to develop Grand Forks, including drilling numerous wells since the purchase and acquiring additional working interests and lands adjoining the initial acquisition.

Grand Forks is now a mature property. Going forward the main task is cost-containment to extend the pool's economic life, which can have a positive impact on NAV, cash flow and distributions.

Success at Crossfield, Alberta.

In addition to oil and natural gas production in the area, PrimeWest's operatorship of the East Crossfield natural gas processing facility is central to the Trust's success. PrimeWest has implemented efficiency and modernization measures, which generated third-party processing fees and extended the plant's economic life.

Strategic control reduced operating costs by 18%



Crossfield Plant

Prior to purchasing an additional interest in the large, sour gas facility at Crossfield in 2000, the Trust paid all operating costs plus 10% to process its area natural gas production, creating a disincentive for the operator to contain costs. As the new operator, PrimeWest's active supervision, investment in equipment automation and staff rationalization have achieved a cumulative reduction in unit operating costs of 18% through year end 2003.

PrimeWest's success at Crossfield illustrates the benefits of controlling and actively managing a strategic facility. The plant's inlet capacity of 142 mmcf/day exceeds the Trust's natural gas production in the area, generating third-party processing fees. PrimeWest's approach has transformed a plant that was forecast for decommissioning as early as 2003, adding at least 10 years to its economic life.

Future investments, such as hydrogen sulphide reinjection to eliminate sulphur emissions, are undergoing feasibility studies.

Success at Caroline, Alberta.

This recently expanded core area offers natural gas and natural gas liquids production, as well as multi-zone drilling potential. Production at Caroline in 2003 averaged approximately 5,100 BOE/day, with operating costs of only $3.04/BOE.

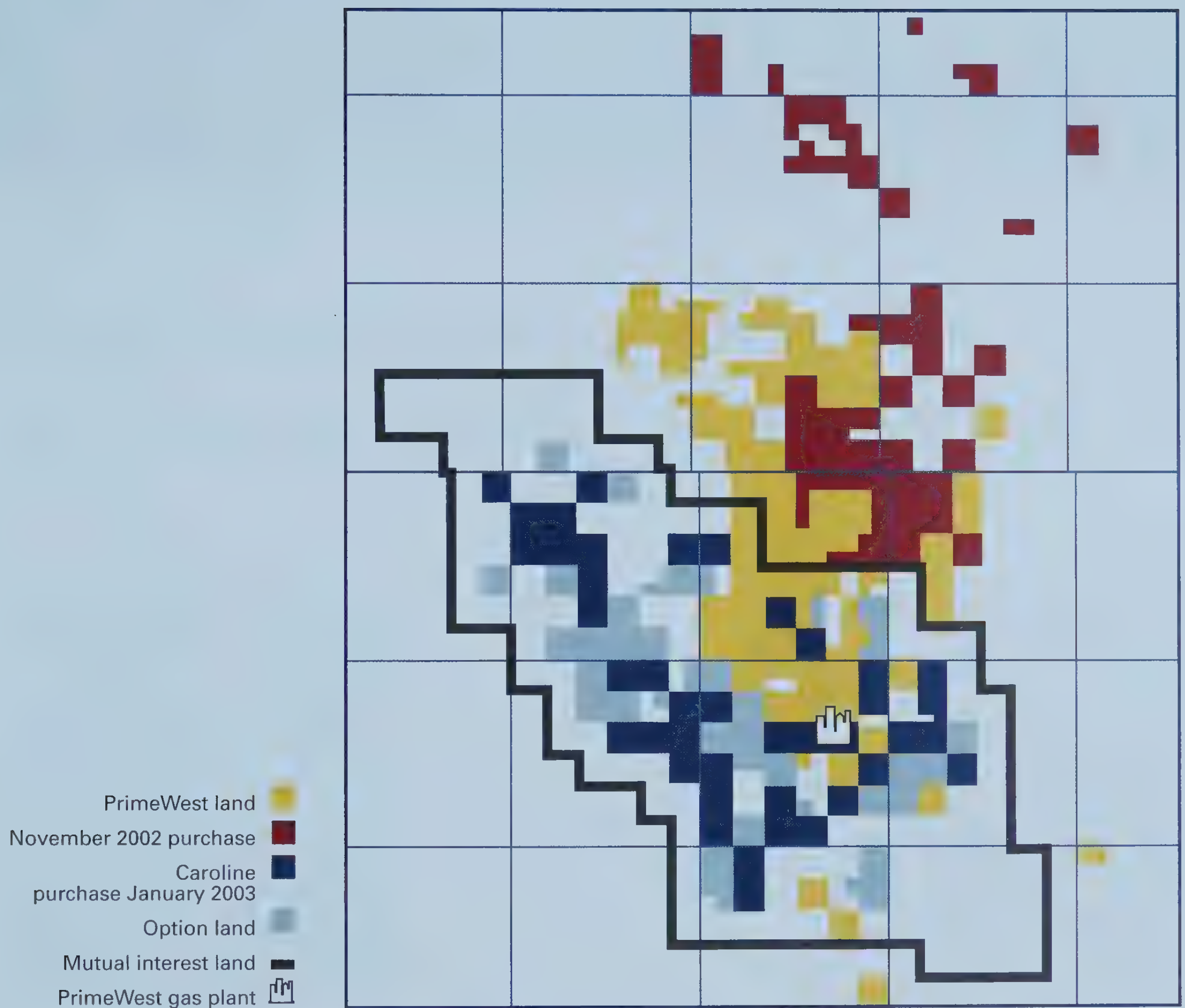
Extensive lands and development upside define PrimeWest's Caroline asset

Profitably tapping the multi-zone natural gas potential of the Caroline-Sundre area depends on several key factors, including a large undeveloped land base and control of area infrastructure and operational decision-making. PrimeWest's recent acquisitions, building on the Trust's presence in the area, meet these criteria. Caroline has become a high volume, low operating-cost property and a key to the Trust's future.

Two recent acquisitions in late 2002 and early 2003, totaling $252 million, gave PrimeWest over 80% working interest in pools producing 30 mmcf/day of sweet natural gas, undeveloped lands totaling 11,000 net acres plus a further 19,000 acres under option, and 100% ownership of a 30 mmcf/day gas plant. The acquisitions enabled PrimeWest to cut operating costs from $6.02/BOE of production to just over $3.00/BOE by the third quarter of 2003.

PrimeWest's current asset base at Caroline represents a significant strengthening of its earlier position. PrimeWest's large land base, control of infrastructure, and inventory of

Caroline Area



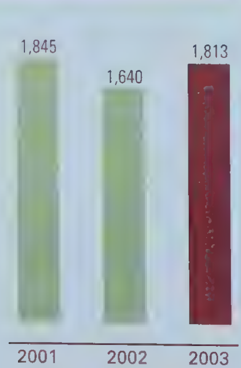
multi-zone gas prospects to 2,700 metres depth, create a strong foundation to help replace annual production declines and to drive further growth in natural gas reserves and volumes.

In 2004, the Trust plans to drill up to 12 medium-depth, higher-impact wells. Successful wells drilled into the Cardium, Viking, Mannville and Elkton formations typically flow at 0.5-2 mmcf/day, incur low operating costs and generate reserves of 1–3 Bcf per successful well.

Success at Brant/Farrow, Alberta.

Brant/Farrow is PrimeWest's most active shallow natural gas property, and in 2003, produced an average of approximately 1,800 BOE/day. PrimeWest has had success shifting focus from deep, high-decline wells to drilling a larger number of lower-productivity/lower-decline wells in the shallow Belly River and Medicine Hat formations.

Shifting from deeper to multi-zone shallow natural gas production



Brant/Farrow Production (BOE/day) Since acquisition of the property in 2001

This all-natural gas property in southern Alberta is the scene of active drilling as PrimeWest shifts from historical deeper natural gas production to multi-zone, shallow natural gas potential. Brant/Farrow offers at least three producing zones at depths of less than 1,000 metres: Medicine Hat, Belly River and Edmonton. Production in 2003 averaged 10 mmcf/day or about 6% of PrimeWest's total corporate volumes.

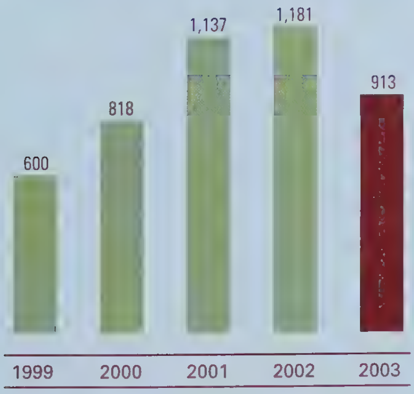
In 2003, PrimeWest accelerated drilling in this highly competitive but opportunity-rich area. The program revealed numerous new prospects and continued to prove up target plays. PrimeWest participated in 39 shallow natural gas wells at Brant/Farrow in 2003, added further undeveloped lands and increased its working interests in existing land holdings. At year end 2003 PrimeWest held approximately 113,000 net acres of undeveloped lands.

The Trust plans to drill 18-25 new shallow natural gas wells in 2004 at Brant/Farrow, offsetting natural decline. Current development plans include several years of ongoing drilling.

Success at Boundary Lake, Alberta.

Boundary Lake, an oil producing area that produced approximately 900 BOE/day in 2003, has been a development property for PrimeWest. It offers a long Reserve Life Index and step-out drilling potential. Future work in Boundary Lake will focus on additional drilling, waterflood enhancement, facilities optimization, and natural gas conservation to maximize the recovery of oil and extend the economic life of the reservoir.

Enhancing production from an under-appreciated asset



Boundary Lake Production (BOE/day)

Boundary Lake demonstrates PrimeWest's ability to recognize upside in an acquired asset that was considered old and tired, and to create new value by applying current technology and active management. In early 2001 PrimeWest shot a large 3-D seismic program to define the edges of the Boundary Lake oil pool. In 2001, PrimeWest launched a successful 10-well drilling program, increasing production to approximately 1,400 BOE/day by the end of that year.

In 2003, PrimeWest further evaluated the western extent of the Boundary Lake pool by reviewing the seismic character attributes. The Trust drilled one well in late 2003 which successfully confirmed the geological model. There is potential for an additional five wells in 2004. PrimeWest will also focus on waterflood optimization and natural gas conservation to maximize the property's economic life.

Land Holdings

The following table summarizes the gross and net acres of unproved properties in which PrimeWest has an interest and also the net value of the undeveloped land.

Area	Gross Acres	Net Acres	Net Value ($ millions)
North			
Boundary Lake	18,301	15,038	1.2
Laprise	6,448	3,919	0.4
Valhalla	26,813	18,955	0.9
North Other	68,761	21,466	1.4
Dawson	211,768	123,871	9.9
Stowe	174,962	143,289	5.7
Central			
Caroline	51,053	35,711	2.8
Crossfield/Lone Pine Creek	4,393	3,234	0.3
Thorsby	53,768	31,991	1.6
Thunder	55,360	22,070	1.0
South			
Jumping Pound/Whiskey Creek	5,278	1,087	0.1
Grand Forks	34,972	17,413	0.7
East Other	26,046	19,639	0.7
Brant/Farrow	113,939	83,404	5.4
Dinosaur/Medicine Hat	7,198	4,181	0.1
Saskatchewan	8,849	6,078	0.3
Non-Core			
Kaybob	4,200	1,420	0.1
Meekwap	7,040	3,124	0.2
Seal	12,640	8,106	0.5
Other	33,494	14,254	0.9
GORR (Gross Overriding Royalties)	176,791	N/A	1.8
Total	1,102,074	578,250	36.0

2003 Drilling Activity

	2003		2002	
	Wells Drilled		Wells Drilled	
	Gross	Net	Gross	Net
Oil	**16**	**4.4**	1	0.3
Natural gas	**79**	**51.4**	55	33.8
Dry holes	**10**	**7.1**	9	6.5
Total	**105**	**62.9**	65	40.6

Production

The following table discloses the 2003 production for each of PrimeWest's core properties, categorized by product type.

	2003 Production			Average Daily Production
Field	Light and Medium Crude Oil (mbbls)	Natural Gas (mmcf)	Natural Gas Liquids (mbbls)	BOE/day
North	**899**	**16,484**	**156**	**10,415**
Boundary Lake	378	153	2	1,110
Laprise	9	3,069	79	1,643
Valhalla	22	4,225	62	2,159
North Other areas	132	2,390	13	1,488
Dawson	292	3,652	–	2,467
Stowe	66	2,995	–	1,548
Central	**251**	**19,775**	**730**	**11,729**
Caroline	81	8,512	382	5,154
Crossfield/Lone Pine Creek	25	4,018	93	2,151
Thorsby	135	6,418	247	3,996
Thunder	10	827	8	428
South	**1,161**	**7,324**	**72**	**6,719**
Jumping Pound/Whiskey Creek	–	1,170	49	667
Grand Forks	942	662	15	2,927
Brant/Farrow	39	3,695	7	1,813
Dinosaur/Medicine Hat	1	1,683	–	767
Saskatchewan	179	114	1	545
Non-Core	**416**	**3,427**	**48**	**2,849**
Kaybob	125	88	8	404
Meekwap	138	93	7	441
Seal	2	1,281	–	591
Other	151	1,965	33	1,413
GORR	**235**	**1,886**	**36**	**1,604**
Total	**2,962**	**48,896**	**1,042**	**33,316**

A letter from the Chair

Barry E. Emes, LL.B.
Director

Mr. Emes is a partner in the corporate/commercial group of the Calgary office of Stikeman Elliott and currently serves as a member of the firm's Partnership Board.

Harold N. Kvisle, P.Eng.
Independent Director

Mr. Kvisle is President, CEO and a director of TransCanada Corporation as well as several companies and limited partnerships within the TransCanada group, and serves as a director of Norske Skog Canada Limited.

Fellow Unitholders

The Board of Directors and management team of PrimeWest have long been committed to a high standard of corporate governance. In our view, effective corporate governance encompasses a number of elements, including specific reporting structures and business processes, a strategic plan and a commitment to work within this framework. For PrimeWest, corporate governance is not limited to the corporate office, but also includes our commitments and responsibilities at the field level. We believe that sound corporate governance throughout the organization contributes to Unitholder value and to continued trust and confidence in PrimeWest.

Securities law dictates that the Board of Directors of PrimeWest Energy Inc. is ultimately responsible for the stewardship of PrimeWest Energy Inc., including the business affairs of PrimeWest Energy Trust. We fulfill this responsibility in part with three Board of Directors' committees consisting of unrelated directors: Audit and Reserves Committee; Compensation Committee; and Corporate Governance and Nominating Committee.

In the rapidly changing regulatory environment, it is expected that companies will come under increased scrutiny from analysts, investors and regulators regarding their corporate governance practices. The Toronto Stock Exchange (TSX) and the New York Stock Exchange (NYSE) have established guidelines and standards for effective corporate governance of the companies listed on their respective exchanges.

With the exception of items pertaining to audit committees, the NYSE rules are not mandatory for foreign issuers like PrimeWest, provided that we disclose any significant ways in which our Canadian corporate governance practices differ from those followed by the NYSE rules for U.S.-based companies. Despite this, we are in substantial compliance

with the NYSE rules, and we also fully comply with the 14 governance guidelines established by the TSX.

Requirements for stronger corporate internal controls were established by the Sarbanes-Oxley Act of 2002 (SOX). As a non-U.S. issuer, PrimeWest has until 2005 to fully comply with certain requirements of SOX. It is our intention to be in full compliance with SOX in 2005.

In keeping with these policies and proposals, PrimeWest's framework of corporate governance is fully disclosed within the management proxy circular issued in connection with the 2004 annual meeting and on our website.

PrimeWest remains committed to complying with existing and proposed corporate governance rules and guidelines. We believe that integrity is central to a publicly traded company and that our corporate governance initiatives will continue to earn the confidence of our loyal Unitholders.

We encourage you to contact us should you have any questions about our corporate governance policies, practices or disclosures.

Sincerely,

Harold Milavsky
Chair of the Board
February 19, 2004

Kent J. MacIntyre, *B.Sc., MBA*
Director

Mr. MacIntyre is the former CEO of PrimeWest and currently serves as a director of BlackRock Ventures Inc., BeauVenture Resources Inc., Canadian Income Fund Group Inc., GLR Solutions Ltd. and various investment trusts comprising the Citadel Group of Funds.

Michael W. O'Brien, *BA, MBA*
Independent Director

Mr. O'Brien held the position of CFO of Suncor Energy Inc. until his retirement in 2002. He currently serves as a director of Terasen Inc., Shaw Communications Inc., and Suncor Energy Inc. He is past Chair of the Nature Conservancy of Canada.

James W. Patek, *M.Sc.*
Independent Director

Mr. Patek is the President of Patek Energy Consultants, based in the United States. He was Chief Executive of Petrocorp Exploration Limited, Chief Executive of Fletcher Challenge Energy and President of Fletcher Challenge Energy Canada.

W. Glen Russell, *P.Eng.*
Independent Director

Mr. Russell is principal of Glen Russell Consulting. He was previously President and COO of Chauvco Resources Limited and Sr. VP and COO of Gulf Canada Resources. Mr. Russell serves as director for a number of private companies.

Environment, Health and Safety

Stewardship of our EH&S Program is a key component of our Corporate Governance at PrimeWest. In 2003, PrimeWest undertook several initiatives to enhance our EH&S programs.

Our accomplishments in 2003 included:

- Achieved a Gold Level Award for participation in the Canadian Association of Petroleum Producers (CAPP) EH&S Stewardship Program for the 2002 company commitment to public consultation and industry benchmarking operating practices. PrimeWest anticipates it will qualify for a Platinum (highest) Level award for 2003 participation.
- Gold Champion Level status was maintained in 2003 for participation in the Voluntary Challenge Registry (VCR), an organization committed to the reduction of greenhouse gas emissions and flaring.
- An in-house competency certification program was implemented for all field operators in 2003, positioning PrimeWest to be compliant with the proposed new 2004 Occupational Health and Safety Regulations.
- Our Licensee Liability Rating (LLR) with the Alberta Energy and Utilities Board (EUB) remained relatively constant year over year, with an LLR rating of 6.31 as of January 2004, compared to 6.19 one year ago. Companies are required to maintain an LLR of greater than 1.0 or a bond may be required prior to the EUB issuing new licenses.
- The contribution rate for our abandonment and reclamation fund was increased to one of the highest in the royalty trust sector at $0.50/BOE.

Management's Discussion and Analysis

The following is management's discussion and analysis (MD&A) of PrimeWest's operating and financial results for the year ended December 31, 2003 compared with the prior year as well as information and opinions concerning the Trust's future outlook based on currently available information. This discussion should be read in conjunction with the Trust's audited consolidated financial statements for the years ended December 31, 2003 and 2002, together with accompanying notes.

Financial and Operating Highlights – Full Year

($ millions, except per BOE and per trust unit amounts)	2003	2002	% Change
Financial			
Net revenue	$ 329.9	$ 264.3	25
Per BOE[1]	27.14	23.98	13
Cash flow from operations	216.6	170.9	27
Per BOE	17.82	15.51	15
Per trust unit[2]	4.67	4.96	(6)
Royalty expense	101.9	56.5	80
Per BOE	8.38	5.13	63
Operating expenses	79.4	60.8	31
Per BOE	6.53	5.52	18
General and administrative expenses – cash	14.5	11.3	28
Per BOE	1.20	1.02	18
General and administrative expenses – non-cash	14.4	6.1	136
Per BOE	1.19	0.55	116
Interest expense	15.1	10.8	40
Per BOE	1.24	0.98	27
Management fees – cash	–	4.0	(100)
Per BOE	–	0.36	(100)
Management fees – non-cash	–	1.4	(100)
Per BOE	–	0.13	(100)
Distributions to Unitholders	192.6	158.0	22
Per trust unit[3]	4.32	4.80	(10)
Net debt[4]	255.9	225.7	13
Per trust unit[5]	5.07	5.75	(12)

[1] All calculations required to convert natural gas to a crude oil equivalent (BOE) have been made using a ratio of 6,000 cubic feet of natural gas to 1 barrel of crude oil. BOEs may be misleading, particularly if used in isolation. The BOE conversion ratio is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.

[2] Weighted average trust units and Exchangeable shares.

[3] Based on trust units outstanding at date of distribution.

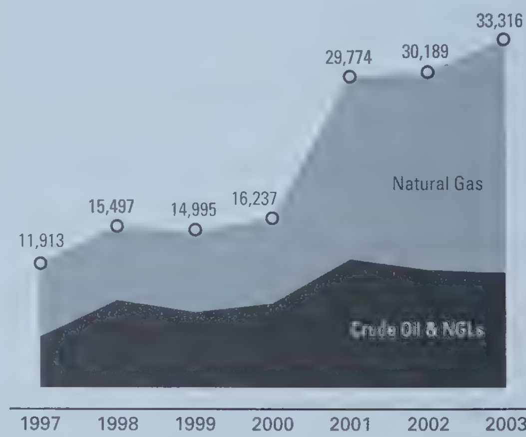
[4] Net debt is long-term debt and adjusted for working capital.

[5] Trust units and Exchangeable shares outstanding (diluted) at end of period.

OPERATING	2003	2002	% Change
Daily sales volume			
Natural gas (mmcf/day)	134.1	113.5	18
Crude oil (bbls/day)	8,116	9,239	(12)
Natural gas liquids (bbls/day)	2,855	2,030	41
Total (BOE/day)	33,316	30,189	10

Financial and Operating Highlights – Full Year

- Production in 2003 averaged 33,316 BOE/day, up 10% from the 2002 level of 30,189 BOE/day as a result of acquisition and development capital volume additions, offset by natural production declines.
- Operating margin of $20.61/BOE for 2003, up 12% from 2002 primarily due to higher commodity prices throughout the year, offset by higher operating costs in 2003, primarily associated with power costs, and third party processing fees.
- Distributions of $4.32 per trust unit in 2003 compared to $4.80 in 2002 reflecting an increased number of units outstanding and lower payout ratio in 2003 compared to 2002. PrimeWest's payout ratio for 2003 was approximately 89%.
- Hedging loss of $30.5 million ($2.51/BOE) in 2003, compared to gains of $28.1 million ($2.55/BOE) in 2002 and gains of $39.5 million ($3.63/BOE) in 2001.
- Capital development program of $104.5 million added 7.9 mmBOE of Proved plus Probable reserves on a Company Interest basis, excluding technical revisions, at $14.29/BOE, which includes an additional $1.06/BOE for future development capital.
- In 2003, PrimeWest made a corporate acquisition as well as a number of property purchases for total expenditures of $230.9 million.



2003 Average Daily Production (BOE/day)

- Operating expenses were 31% higher in 2003 compared to 2002, primarily as a result of higher power costs, third party processing fees, and increased volumes from acquisitions.
- Net Proved plus Probable reserves of 85.8 mmBOE at December 31, 2003, represents an increase of 1.5% from 84.5 mmBOE reported on a net Established reserves basis as at December 31, 2002. PrimeWest's current Reserve Life Index (RLI) is 10.2 years on a Net Proved plus Probable basis. (See page 38 for reserve definitions).

- Net Proved Producing reserves of 62.8 mmBOE at December 31, 2003, represents an increase of 3% over the December 31, 2002 Net Proved Producing reserves of 60.9 mmBOE. Current Net Proved Producing RLI is 7.5 years with total Net Proved RLI at 8.2 years.
- Company Interest Proved plus Probable reserves of 106.8 mmBOE at December 31, 2003 represents an increase of 2% from 104.4 mmBOE reported on a Company Interest Established reserves basis at December 31, 2002. PrimeWest's current Company Interest Proved plus Probable RLI is 9.8 years, compared with an RLI of 9.5 years on a Company Interest Established basis in 2002.
- Company Interest Proved Producing reserves of 77.5 mmBOE at December 31, 2003 represent an increase of 4% over the December 31, 2002 Company Interest Proved Producing reserves of 74.7 mmBOE.
- Cash general and administrative expenses increased $3.2 million over 2002, reflecting higher salary costs as a result of hiring additional technical staff and one-time costs associated with evaluating international opportunities.
- Interest expense during 2003 is 40% higher compared to 2002 as a result of higher average debt levels throughout the year.
- Raised $32.4 million from the Distribution Reinvestment, Premium Distribution and Optional trust unit Purchase Plans. Proceeds were used for the capital development program and to repay debt.
- As a result of internalization of management in November, 2002 the Trust did not incur any management fees for 2003. In 2002, the Trust paid management fees of $5.4 million for the period January to September of 2002.
- Completed US$125 million private placement debt financing of secured notes at a coupon rate of 4.19% and a seven year term.

Subsequent Events

- On January 27th, 2004 PrimeWest announced an offer to acquire all of the shares of Seventh Energy Ltd. Seventh Energy's Board and executive unanimously approved the transaction and have agreed to tender their approximately 24% ownership interest. The acquisition cost is expected to be $42.6 million comprised of the assumption of $8.3 million of debt and working capital and a cash payment of $34.3 million. To protect the transaction economics, PrimeWest hedged approximately 70% of Seventh Energy's natural gas production at a price of $6.18/mcf for one year. PrimeWest's existing credit line will be used to fund the cash portion of the acquisition. The offer is currently set to expire on March 15, 2004.
- On February 11, 2004 PrimeWest announced that in keeping with its strategy of targeting a payout ratio of 70-90% of cash flow from operations, the March 15, 2004 distribution would be Cdn$0.25 per trust unit. The decision to lower the distribution payout is a result of our near-term forecast of production, commodity prices and the U.S./Canadian dollar exchange rate.

Consolidation of Trust Units

On August 16, 2002 the trust units of PrimeWest began trading on a four to one consolidated basis on the TSX. All per trust unit amounts have been restated to conform to the four to one consolidated basis.

Forward-Looking Information

This MD&A contains forward-looking or outlook information with respect to PrimeWest.

The use of any of the words "anticipate", "continue", "estimate", "expect", "may", "will", "project", "should", "believe", "outlook" and similar expressions are intended to identify forward-looking statements. These statements involve known and unknown risks, uncertainties and other factors that may cause actual results or events to differ materially from those anticipated in our forward-looking statements. We believe the expectations reflected in those forward-looking statements are reasonable. However, we cannot assure you that these expectations will prove to be correct. You should not unduly rely on forward-looking statements included in this report. These statements speak only as of the date of this MD&A.

In particular, this MD&A contains forward-looking statements pertaining to the following:

- The quantity and recoverability of our reserves;
- The timing and amount of future production;
- Prices for oil, natural gas, and natural gas liquids produced;
- Operating and other costs;
- Business strategies and plans of management;
- Supply and demand for oil and natural gas;
- Expectations regarding our ability to raise capital and to add to our reserves through acquisitions and exploration and development;
- Our treatment under governmental regulatory regimes;
- The focus of capital expenditures on development activity rather than exploration;
- The sale, farming in, farming out or development of certain exploration properties using third party resources;
- The objective to achieve a predictable level of monthly cash distributions;
- The use of development activity and acquisitions to replace and add to reserves;
- The impact of changes in oil and natural gas prices on cash flow after hedging;
- Drilling plans;
- The existence, operations and strategy of the commodity price risk management program;
- The approximate and maximum amount of forward sales and hedging to be employed;

- The Trust's acquisition strategy, the criteria to be considered in connection therewith and the benefits to be derived there from;
- The impact of the Canadian federal and provincial governmental regulation on the Trust relative to other oil and gas issuers of similar size;
- The goal to sustain or grow production and reserves through prudent management and acquisitions;
- The emergence of accretive growth opportunities; and
- The Trust's ability to benefit from the combination of growth opportunities and the ability to grow through the capital markets.

Our actual results could differ materially from those anticipated in these forward-looking statements as a result of the risk factors set forth below and elsewhere in this MD&A.

- Volatility in market prices for oil and natural gas;
- Risks inherent in our oil and natural gas operations;
- Uncertainties associated with estimating reserves;
- Competition for, among other things: capital; acquisitions of reserves; undeveloped lands and skilled personnel;
- Incorrect assessments of the value of acquisitions;
- Geological, technical, drilling and processing problems;
- General economic conditions in Canada, the U.S. and globally;
- Industry conditions, including fluctuations in the price of oil and natural gas;
- Royalties payable in respect of PrimeWest's oil and natural gas production;
- Governmental regulation of the oil and natural gas industry, including environmental regulation;
- Fluctuation in foreign exchange or interest rates;
- Unanticipated operating events that can reduce production or cause production to be shut-in or delayed;
- Failure to obtain industry partner and other third party consents and approvals, when required;
- Stock market volatility and market valuations;
- The need to obtain required approvals from regulatory authorities; and
- The other factors discussed under "Operational and Other Business Risks" in this MD&A.

These factors should not be construed as exhaustive.

Evaluation of Disclosure Controls and Procedures

The Chief Executive Officer, Don Garner, and Chief Financial Officer, Dennis Feuchuk, evaluated the effectiveness of PrimeWest Energy's disclosure controls and procedures as of December 31, 2003 and concluded that PrimeWest Energy's disclosure controls and procedures were effective to ensure that information PrimeWest is required to disclose in its filings with the Securities and Exchange Commission under the Securities Exchange Act of 1934 is recorded,

processed, summarized and reported, within the time periods specified in the Commission's rules and forms, and to ensure that information required to be disclosed by PrimeWest in the reports that it files under the Exchange Act is accumulated and communicated to PrimeWest's management, including its principal executive officer and principal financial officer, as appropriate to allow timely decisions regarding required disclosure.

Vision, Core Business and Strategy

PrimeWest Energy Trust is a conventional oil and gas royalty trust actively managed to generate monthly cash distributions for Unitholders. The Trust's operations are focused in Canada, with its assets concentrated in the Western Canada Sedimentary Basin. PrimeWest is one of North America's largest natural gas weighted energy trusts.

Maximizing total return to Unitholders, in the form of cash distributions and change in unit price, is PrimeWest's overriding objective. Our strategies for asset management and growth, financial management and corporate governance are outlined in this MD&A, along with a discussion of our performance in 2003 and our goals for 2004 and beyond.

We believe that PrimeWest can maximize total return to Unitholders through the continued development of our core properties, making opportunistic acquisitions that emphasize value creation, exercising disciplined financial management which broadens access to capital while minimizing risk to Unitholders, and complying with strong corporate governance to protect the interests of all stakeholders.

Asset Management and Growth

PrimeWest has a strategy to focus our expansion efforts on existing Canadian core areas, and pursue field development and optimization within those core areas to maximize asset value. We strive to control our operations whenever possible, and maintain high working interests. Maintaining control of 80% of operations allows us to use existing infrastructure and synergies within our core areas. We believe this high level of operatorship can translate to control over costs and timing of capital outlays and projects. We will continue to be an opportunistic acquirer that uses the business cycles to make accretive acquisitions. The current size of the Trust gives us the ability and critical mass to make acquisitions of significant size, while still being able to add value by transacting smaller acquisitions.

Financial Management

PrimeWest strives to maintain a conservative debt position, to position us to take advantage of opportunities that arise in the acquisition market, as well as fund development activities. Our diversified debt instruments help to reduce our reliance on the bank syndicate, as well as afford additional foreign exchange protection because a portion of our debt, the secured notes, is denominated in U.S. dollars. PrimeWest's consistent commodity hedging approach helps to stabilize cash flow, reduce volatility, and protect transaction economics.

In the interests of the future sustainability of the Trust, during 2003 PrimeWest began easing its distribution payout ratio from the historic highs of 95% downward to a targeted range of between 70%-90% annually. The 2003 payout ratio was approximately 89%. Retention of some internally-generated cash flow is designed to help keep the balance sheet strong and give more financial flexibility to PrimeWest in an increasingly competitive environment. Our success in executing prudent financial management in 2003 is demonstrated by our year end debt to cash flow level of 1.2 times, less than our internal limit of 2.0 times and slightly lower than our 2002 year end level of 1.3 times.

PrimeWest's dual listing on both the Toronto Stock Exchange (TSX) and New York Stock Exchange (NYSE) has provided increased liquidity and greatly broadened our investor base. The NYSE listing enables U.S. Unitholders to conveniently trade in our trust units, allows us to access the U.S. capital markets in the future, and our status as a corporation for U.S. tax purposes simplifies tax reporting for our U.S. Unitholders. For eligible Canadian Unitholders, PrimeWest offers participation in the Distribution Reinvestment Plan (DRIP), Premium Distribution Plan (PREP), or Optional trust unit Purchase Plan (OTUPP), all of which represent a convenient way to maximize an investment in PrimeWest. For alternate investment styles, PrimeWest also has Exchangeable shares available, which permit participation in PrimeWest without the ongoing tax complications associated with receiving a distribution.

Corporate Governance

PrimeWest remains committed to the highest standards of corporate governance. Each regulatory body has a different set of rules pertaining to corporate governance, including the Toronto Stock Exchange, the New York Stock Exchange, the Canadian provincial securities commissions and the U.S. Securities and Exchange Commission (whose responsibilities include implementing rules under the United States' Sarbanes-Oxley Act of 2002). PrimeWest upholds the rules of the governing bodies under which it operates, and in many cases, we already comply with proposals and recommendations that have not yet come into force. We provide full disclosure of this compliance within our proxy circular and on our website. In 2003, we strengthened our Board by adding two additional independent directors, and assigned committee leadership only to independent directors.

Our high standards of corporate governance are not limited to the boardroom. At the field level, PrimeWest proactively manages environmental, health and safety issues. We place a great deal of importance on community involvement and maintaining good relationships with landowners.

2004 Outlook

PrimeWest expects 2004 production volumes to average approximately 30,000 BOE/day. Full year operating costs are expected to be approximately $6.75/BOE, while full year general and administrative costs are expected to be approximately $1.25/BOE. PrimeWest expects to spend between $65 and $90 million on its 2004 capital development program, with the focus primarily in the core areas of Caroline, Valhalla, Brant/Farrow and Princess/Hays. This outlook assumes the successful completion of the Seventh Energy acquisition. Based on current expectations for capital spending and cash flow for 2004, it is anticipated that approximately 60% of 2004 distributions will be taxable and 40% will be deemed return of capital for Unitholders resident in Canada. The taxability of 2004 distributions for U.S. Unitholders cannot be accurately estimated and will be confirmed after year end. For residents of the U.S., Canadian withholding tax of 15% applies to the distribution. For more details on withholding tax, please visit our website at www.primewestenergy.com.

Cash Flow Reconciliation

($ millions)

2002 cash flow from operations	$ 170.9
Production volumes	22.5
Commodity prices	148.3
Net hedging change from prior year	(58.6)
Operating expenses	(18.6)
Royalties	(45.4)
Other	(2.5)
2003 cash flow from operations	**$ 216.6**

The above table includes non-GAAP measurements.

The basis of PrimeWest's business and a key performance driver for the Trust is cash flow from operations. Cash flow is generated through the production and sale of crude oil, natural gas and natural gas liquids, and is dependent on production levels, commodity prices, operating expenses, hedging gains or losses, royalties and currency exchange rates. Cash flow from operations can be impacted by macro factors such as commodity prices, the currency exchange rate, royalties and the forward markets for oil and natural gas. Cash flow can also be impacted by factors specific to PrimeWest such as production levels, hedging gains or losses, or operating expenses, as well as interest and general and administrative expenses. It is expected that these factors will impact cash flows in the future.

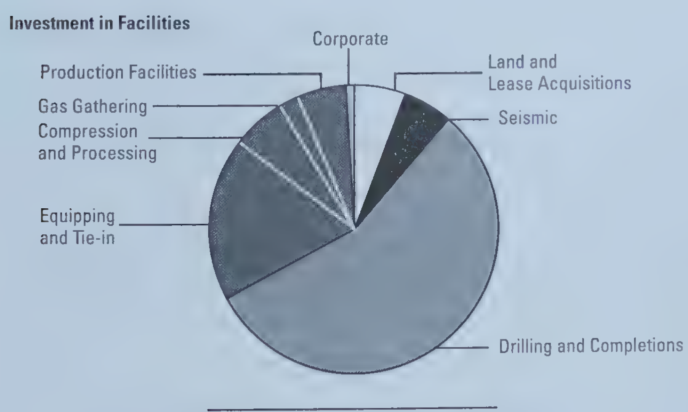
Capital Spending

Capital expenditures, including development and acquisitions, totaled approximately $334.4 million in 2003, versus $124.1 million in 2002.

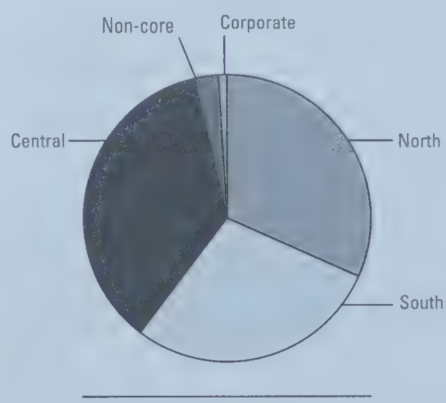
PrimeWest's capital development program for 2003 was the largest in its history, and totaled $104.5 million (2002 – $64.2 million). As commodity prices increased and potential acquisition assets became more expensive through 2003, PrimeWest increased its capital spending on internal development opportunities. Rather than risk undertaking an acquisition that did not meet economic thresholds for adding value, PrimeWest instead focused on adding reserves via development.

PrimeWest's capital program in 2003 was focused on specific core areas, with approximately 31% ($33.3 million) of the program invested in facilities to increase capacity or undertake upgrades to improve efficiencies. These benefits are expected to be realized in 2004 and beyond. The development program added 7.9 mmBOE of Company Interest Proved plus Probable reserves at a cost of $14.29/BOE, including future development capital of $1.06/BOE. This figure does not reflect the impact of technical revisions.

In 2003, PrimeWest completed $228.6 million in net property acquisitions (2002 – $56.5 million) adding 12.7 mmBOE of Company Interest Proved reserves and 15.6 mmBOE of Company Interest Proved plus Probable reserves. In 2002, PrimeWest's acquisitions included $13.2 million to acquire the 1% retained royalty as part of the internalization of management plus $0.8 million in capitalized costs to effect the internalization.



Capital Spending by Activity



Capital Spending by Area

Capital Spending

($ millions, except per BOE)	2003	2002
Land and lease acquisitions	$ 6.0	$ 5.7
Geological and geophysical	5.8	1.8
Drilling and completions	58.4	33.4
Investment in facilities		
Equipping and tie-in	19.0	6.4
Compression and processing	6.3	9.7
Gas gathering	2.3	2.2
Production facilities	5.7	4.0
Capitalized general and administrative	1.0	1.0
Development capital	104.5	64.2
Corporate/property acquisitions	230.9	61.0
Dispositions	(2.3)	(4.5)
Head office equipment	1.3	3.4
Total	$ 334.4	$ 124.1

	2003	2002
Development Program		
Proved reserve additions (mmBOE)[1]	6.9	6.3
Average cost ($/BOE)[2]	$ 15.98	$ 11.06
Proved plus Probable reserve additions (mmBOE)[1]	7.9	8.7
Average cost ($/BOE)[1]	$ 14.29	$ 8.29
Acquisition Program[3]		
Proved reserve additions (mmBOE)[1]	12.7	3.4
Average cost ($/BOE)[2]	$ 18.84	$ 17.49
Proved plus Probable reserve additions (mmBOE)[1]	15.6	3.6
Average cost ($/BOE)[2]	$ 15.71	$ 16.60

[1] Company Interest reserve additions, includes infill drilling, reserves that are included in technical revisions, in the reserves table.

[2] Under NI 51-101 (see discussion below under "Reserves and Production"), the implied methodology to be used to calculate FD&A costs includes incorporating changes in future development capital (FDC) required to bring the Company Interest Proved Undeveloped and Probable reserves to production. The average cost per BOE from Company Interest Proved reserve additions includes FDC of $0.84/BOE ($0.87/BOE for 2002), and the average cost/ BOE from Company Interest Proved plus Probable reserve additions includes FDC of $1.06/BOE ($0.91/BOE for 2002). The aggregate of the exploration and development costs incurred in the most recent financial year and the change during that year in estimated future development costs generally will not reflect total finding and development costs related to reserve additions for that year.

[3] Net of dispositions and adjusted for technical performance and NI 51-101.

PrimeWest's development program for 2003 totaled $104.5 million. Of this amount, 56% was spent on drilling and completions, which contributed to new reserve additions. A significant portion of the investments made in facilities represents debottlenecking, increasing capacity or other activities which contribute to future production volumes.

In 2004, PrimeWest plans to spend between $65-90 million on its capital development programs. The 2004 program will primarily be focused in our core areas of Brant/Farrow, Caroline, and Valhalla, with approximately $7 million of the total budgeted amount for activities in the Princess/Hays area with the completion of the Seventh Energy acquisition.

Given that production volumes will decline naturally over time as oil or natural gas reservoirs are depleted, PrimeWest is always striving to offset this natural production decline, and add to reserves in an effort to sustain cash flows. Investment in activities such as development drilling, workovers, and recompletions can add incremental production volumes and reserves.

Capital is allocated on the basis of anticipated rate of return on projects undertaken. At PrimeWest, every capital project is measured against stringent economic evaluation criteria prior to approval (these include expected return, risks and further development opportunities).

Assets

Since inception, PrimeWest has focused on the conventional oil and natural gas plays of the Western Canada Sedimentary Basin. Within this focused area, we have a diversified, multi-zone suite of assets stretching from northeast B.C., across much of Alberta and down through southwest Saskatchewan. We believe this diversity reduces risks to overall corporate production and cash flow, while the core area focus allows us to capitalize on our existing technical knowledge in each of the core areas. Our operations staff are grouped into three teams – North, Central and South – with each being responsible for production and development of assets that are geographically located within those regions of the Basin.

During 2003, PrimeWest had 15 core area assets which in aggregate produced 87% of the Company's total production volumes for the year. No core area produced greater than 20% of PrimeWest's total volumes, and PrimeWest is the operator in all but two core areas. With the acquisition of Seventh Energy, the Trust intends to expand its existing Princess/Hays region of southeast Alberta. This is an example of the Trust's strategy to expand existing areas or build new core areas within which we retain control of operations.

Reserves and Production

In 1998, the Alberta Securities Commission established an oil and natural gas taskforce to investigate methods of improving oil and natural gas reserve reports prepared pursuant to National Policy Statement 2-B (NP 2B), the existing legislative regime. The taskforce sent its findings and recommendations to the Canadian Securities Administrators in 2001, which ultimately initiated its own extensive public consultative process, culminating with National Instrument 51-101 (NI 51-101) which came into force on September 30, 2003. NI 51-101 reflects a departure from its predecessor NP 2B, attempting to address the perceived shortcomings of NP 2B by improving the standards and quality of reserve reporting and achieving a higher industry consistency.

Under NI 51-101, Proved reserves are those reserves that can be estimated with a high degree of certainty to be recoverable (i.e. it is likely that the actual remaining quantities recovered will exceed the estimated Proved reserves). In accordance with this definition, the level of certainty targeted by the reporting company should result in at least a 90% probability that the quantities actually recovered will equal or exceed the estimated Proved reserves. While the definition itself is similar to the old definition of Proved reserves, there was no consideration of probability under NP 2B. In the case of Probable reserves, which are by definition less certain to be recovered than Proved reserves, NI 51-101 states that it must be equally likely that the actual remaining quantities recovered will be greater or less than the sum of the estimated Proved plus Probable reserves. With respect to the consideration of certainty, in order to report reserves as Proved plus Probable, the level of certainty targeted by the reporting company should result in at least a 50% probability that the quantities actually recovered will equal or exceed the sum of the estimated Proved plus Probable reserves. The implementation of NI 51-101 has resulted in a more rigorous and uniform standardization of reserve evaluation.

Proved plus Probable reserves replace the "Established" reserves definition that was used historically. Under the old rules, the Established reserves category was generally calculated on the basis that Proved plus half of Probable reserves (as those terms were defined in NP 2B) represented the best estimate at the time. PrimeWest believes that its Established reserves reported under NP 2B were calculated on a reasonable basis as its estimate of reserves that would ultimately be recovered. As a result, and for comparison purposes, we have included Established reserves from our December 31, 2002 reserves report as our December 31, 2002 opening balances under the Proved plus Probable reserves category reconciled on a Company Interest basis and on a Net basis (see discussion below). Similarly, we have included 50% of Probable reserves from our December 31, 2002 reserves report as our opening balances under the Probable reserves category, again reconciled on a Company Interest basis and on a Net basis.

Before the implementation of NI 51-101, reporting companies reported and reconciled reserves on a Company Interest basis, which included working interest reserves plus royalties receivable (with no deduction for royalties payable). Under the new rules, companies are required to report Gross Reserves, which include working interest with no adjustment for royalties payable or royalties receivable. Companies must also report and reconcile Net reserves (working interest and royalties receivable, less royalties payable). As required, PrimeWest has reported its reserves on a Gross and Net basis. In addition, we have reconciled our reserves on a Net basis. Again, for continuity and comparison purposes, we have also reported and reconciled our reserves using the old Company Interest definition.

Unless otherwise stated, all of the reserves information contained in this annual report has been calculated and reported in accordance with NI 51-101. PrimeWest's complete NI 51-101 reserves disclosure as at December 31, 2003, including underlying assumptions regarding commodity prices, expenses and other factors are available in the Trust's Annual Information Form and on our corporate website at www.primewestenergy.com.

The following table sets forth a reconciliation of the Company Interest reserves of PrimeWest for the year ended December 31, 2003 derived from the report of the independent reserve evaluators, Gilbert Laustsen Jung Associates Ltd (GLJ), using the consultant's average pricing. These year end reserves are reconciled to December 31, 2002 Established reserves. PrimeWest's Company Interest reserves include working interest and royalties receivable. All data in the following tables was provided by GLJ.

Company Interest Reserves – Consultant's Average Pricing

	Light, Medium and Heavy Crude Oil (mbbls)				Natural Gas (bcf)			
	Proved Producing	Total Proved	Probable	Proved plus Probable	Proved Producing	Total Proved	Probable	Proved plus Probable
December 31, 2002	20,136.2	21,416.2	3,043.9[a]	24,460.1[b]	286.6	349.5	69.0[a]	418.5[b]
Capital additions[d]	832.8	575.9	43.0	618.9	20.4	18.8	2.6	21.4
Technical revisions[e]	263.4	10.3	99.2	109.5	(6.9)	(35.5)	4.4	(31.1)
Acquisitions	436.9	436.9	71.9	508.8	57.3	64.0	16.2	80.2
Dispositions	(28.0)	(28.0)	(5.0)	(33.0)	(0.2)	(1.0)	(2.0)	(3.0)
Economic factors	197.0	128.0	71.0	199.0	(3.4)	(3.7)	(1.2)	(4.9)
Production	(2,984.3)	(2,984.3)	0.0	(2,984.3)	(48.9)	(48.9)	0.0	(48.9)
December 31, 2003	**18,854.0**	**19,555.0**	**3,324.0**	**22,879.0**[c]	**304.9**	**343.2**	**89.0**	**432.2**[c]

	Natural Gas Liquids (mbbls)				Barrel of Oil Equivalent (mmBOE)			
	Proved Producing	Total Proved	Probable	Proved plus Probable	Proved Producing	Total Proved	Probable	Proved plus Probable
December 31, 2002	6,795.3	8,448.3	1,740.7[a]	10,189.0[b]	74.7	88.1	16.3[a]	104.4[b]
Capital additions[d]	497.3	590.0	130.3	720.3	4.7	4.3	0.6	4.9
Technical revisions[e]	(8.9)	(749.9)	534.8	(215.1)	(0.8)	(6.7)	1.4	(5.3)
Acquisitions	1,565.3	1,747.7	489.7	2,237.4	11.6	12.9	3.2	16.1
Dispositions	(1.1)	(3.2)	(1.5)	(4.7)	(0.1)	(0.2)	(0.3)	(0.5)
Economic factors	(8.0)	(16.0)	(6.0)	(22.0)	(0.4)	(0.5)	(0.1)	(0.6)
Production	(1,041.9)	(1,041.9)	0.0	(1,041.9)	(12.2)	(12.2)	0.0	(12.2)
December 31, 2003	**7,798.0**	**8,975.0**	**2,888.0**	**11,863.0**[c]	**77.5**	**85.7**	**21.0**	**106.8**[c]

Columns may not add due to rounding.

[a] Amount equals 50% of Probable reserves reported in PrimeWest's December 31, 2002 reserves report.

[b] Proved plus Probable figures for December 31, 2002 represent Established reserves from PrimeWest's December 31, 2002 reserves report. Proved plus Probable illustrates the reconciliation between Established reserves as at December 31, 2002 under NP 2B to Proved plus Probable reserves as at December 31, 2003 under NI 51-101. See initial discussion above under "Reserves and Production".

[c] Proved plus Probable reserves reflect at least a 50% probability that the quantities actually recovered will equal or exceed the sum of the estimated Proved plus Probable reserves.

[d] Includes discoveries, extensions, and improved recoveries.

[e] Includes infill drilling.

The following table is the reconciliation of PrimeWest's Net reserves for the year ended December 31, 2003 using consultant's average pricing and cost estimates, as required under NI 51-101 guidelines and format. These year end reserves are reconciled to December 31, 2002 Established reserves. Net reserves include working interest reserves plus royalties receivable less royalties payable.

Net Reserves – Consultant's Average Pricing

	Light and Medium Crude Oil (mbbls)				Heavy Oil (mbbls)			
	Proved Producing	Total Proved	Probable	Proved plus Probable	Proved Producing	Total Proved	Probable	Proved plus Probable
December 31, 2002	14,641.0	15,355.0	2,252.0[a]	17,607.0[b]	3,320.0	3,723.0	405.0[a]	4,128.0[b]
Extensions	11.9	49.2	40.8	90.0	37.6	37.6	24.9	62.5
Improved recovery	451.6	443.0	(26.1)	416.9	265.1	0.0	0.0	0.0
Technical revisions[d]	672.3	470.6	199.1	669.7	(441.0)	(406.9)	(52.5)	(459.4)
Discoveries	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Acquisitions	219.1	219.1	36.5	255.6	156.5	156.5	24.6	181.1
Dispositions	(21.4)	(21.4)	(4.3)	(25.7)	(2.7)	(2.7)	0.0	(2.7)
Economic factors	(104.0)	(100.0)	6.0	(94.0)	290.0	221.0	33.0	254.0
Production	(1,586.5)	(1,586.5)	0.0	(1,586.5)	(769.5)	(769.5)	0.0	(769.5)
December 31, 2003	**14,284.0**	**14,829.0**	**2,504.0**	**17,333.0**[c]	**2,856.0**	**2,959.0**	**435.0**	**3,394.0**[c]

	Associated and Non-Associated Gas (Natural Gas) (bcf)				Natural Gas Liquids (mbbls)			
	Proved Producing	Total Proved	Probable	Proved plus Probable	Proved Producing	Total Proved	Probable	Proved plus Probable
December 31, 2002	228.0	277.5	54.5[a]	331.9[b]	4,927.0	6,140.0	1,259.0[a]	7,399.0[b]
Extensions	10.0	9.8	2.0	11.8	69.6	70.8	8.4	79.2
Improved recovery	5.8	4.8	0.1	4.9	278.5	342.2	82.4	425.0
Technical revisions[d]	(7.6)	(30.8)	3.3	(27.4)	(25.8)	(613.0)	360.5	(252.9)
Discoveries	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Acquisitions	41.8	46.7	11.8	58.5	1,095.7	1,223.4	342.8	1,566.2
Dispositions	(0.2)	(0.8)	(1.6)	(2.3)	(0.8)	(2.2)	(1.1)	(3.3)
Economic factors	(0.3)	(0.5)	(0.1)	(0.5)	(6.0)	(12.0)	(1.0)	(13.0)
Production	(36.9)	(36.9)	0.0	(36.9)	(768.2)	(768.2)	0.0	(768.2)
December 31, 2003	**240.7**	**269.9**	**70.1**	**339.9**[c]	**5,570.0**	**6,381.0**	**2,051.0**	**8,432.0**[c]

	Total (mmBOE)			
	Proved Producing	Proved	Probable	Proved plus Probable
December 31, 2002	60.9	71.5	13.0[a]	84.5[b]
Extensions	1.8	1.8	0.4	2.2
Improved recovery	2.0	1.6	0.1	1.7
Technical revisions[d]	(1.1)	(5.7)	1.1	(4.6)
Discoveries	0.0	0.0	0.0	0.0
Acquisitions	8.4	9.4	2.4	11.8
Dispositions	(0.1)	(0.2)	(0.3)	(0.4)
Economic factors	0.1	0.0	0.0	0.1
Production	(9.3)	(9.3)	0.0	(9.3)
December 31, 2003	**62.8**	**69.1**	**16.7**	**85.8**[c]

Columns may not add due to rounding.

[a] Amount equals 50% of Probable reserves reported in PrimeWest's December 31, 2002 reserves report.

[b] Proved plus Probable figures for December 31, 2002 represent Established reserves from PrimeWest's December 31, 2002 reserves report. Proved plus Probable illustrates the reconciliation between Established reserves as at December 31, 2002 under NP 2B to Proved plus Probable reserves as at December 31, 2003 under NI 51-101. See initial discussion above under "Reserves and Production".

[c] Proved plus Probable reserves reflect at least a 50% probability that the quantities actually recovered will equal or exceed the sum of the estimated Proved plus Probable reserves.

[d] Includes infill drilling.

Production Volumes

	2003	2002	Change (%)
Natural gas (mmcf/day)	**134.1**	113.5	18
Crude oil (bbls/day)	**8,116**	9,239	(12)
Natural gas liquids (bbls/day)	**2,855**	2,030	41
Total (BOE/day)	**33,316**	30,189	10
Gross Overriding Royalty volumes included above (BOE/day)	**1,604**	1,772	(9)

All production information is reported before the deduction of Crown and freehold royalties.

The 10% increase in production volumes year-over-year is due to the acquisition of the Caroline/Peace River Arch properties, completed in January of 2003, combined with development additions, and offset by natural decline. During 2003, natural production decline averaged approximately 20%. Through the year, approximately 3,060 BOE/day of incremental production was brought on-line from development activities to mitigate decline. Approximately 1,700 BOE/day remained behind pipe at the end of 2003.

PrimeWest expects production for full year 2004 to be approximately 30,000 BOE/day. This estimate incorporates PrimeWest's expected natural decline rate, production volume shut-ins described in greater detail on page 42, as well as

the offset of production additions due to the capital development program and the expected acquired production from the purchase of Seventh Energy.

It is anticipated that production from PrimeWest's non-operated Ells property in Northeast Alberta will be subject to shut-in by the Alberta Energy and Utilities Board prior to spring break-up, as a result of the gas-over-bitumen issue. PrimeWest is seeking compensation for the loss of revenue that will result from the shut-in of this production. An additional shut-in at PrimeWest's non-operated Whiskey Creek area due to facility capacity constraints, will result in PrimeWest's volumes being temporarily shut-in. These shut-ins are anticipated to impact PrimeWest by approximately 1,000 BOE/day of natural gas production. These shut-ins at non-operated properties highlight the importance of PrimeWest's strategy of maintaining control of operations wherever possible, thereby retaining control of projects and timing.

Commodity Prices

Benchmark Prices	**2003**	2002	Change (%)
Natural gas ($/mcf AECO)	**$ 6.70**	$ 4.07	65
Crude oil (US$/bbl WTI)	**$ 31.04**	$ 26.08	19

Average Realized Sales Prices[1] (Canadian dollars)	**2003**	2002	Change (%)
Natural gas ($/mcf)	**$ 6.05**	$ 4.55	33
Crude oil ($/bbl)	**33.94**	33.53	1
Natural gas liquids ($/bbl)	**35.34**	26.56	33
Total oil equivalent[2] ($/BOE)	**$ 35.68**	$ 29.16	22
Realized hedging gain (loss) included in prices above ($/BOE)	**$ (2.51)**	$ 2.55	(198)

[1] Includes hedging gains/losses.
[2] Excludes sulphur.

During 2003 commodity prices were generally higher than in 2002, with average realized selling prices per BOE increasing by 22% in 2003 over 2002. Within this higher commodity price environment, PrimeWest realized an average loss of $2.51/BOE due to hedging. This loss does not represent a cash expenditure, but is the calculation of the additional revenue PrimeWest would have generated had it not sold production on a hedged basis. PrimeWest's cash flow from operations is directly impacted by commodity prices, but the use of hedging can increase or decrease the prices realized by the Trust. PrimeWest's hedging program delivered gains of $37.1 million between January 1, 2001 and December 31, 2003 and remains an important element in PrimeWest's financial management strategy. The hedging program is designed to reduce commodity price volatility, increase cash flow stability and protect the economics of acquisitions.

The realized selling price in Canadian dollars is also impacted by currency exchange rates. Oil and natural gas prices are denominated in U.S. dollars, therefore, a strengthened Canadian dollar translates into lower realized prices and lower Canadian revenue for producers. Throughout 2003, the Canadian dollar strengthened by more than 20%. At December 31, 2002 the Canadian dollar was $0.6334 versus its U.S. counterpart, compared to $0.7673 at December 31, 2003. With oil and natural gas prices denominated in U.S. dollars, the strengthening Canadian dollar during 2003 continued to negatively impact Canadian dollar realizations.

Natural Gas Pricing — Historical and Forward Strip
(Cdn$/mcf)
Historical AECO Natural Gas Price
Forward Strip at December 31, 2003

Crude Oil Prices – Crude oil prices fluctuated significantly during 2003, reflecting uncertainties around the globe. Contributing factors include erratic production of oil in an unstable post-war Iraq; supply management by the members of OPEC; ongoing civil unrest in Nigeria and Venezuela; record low storage levels of oil being maintained by refiners in the contiguous U.S.; and a recovering U.S. economy. The weakness of the U.S. dollar in relation to most of the rest of the world's currencies has had the effect of increasing the purchasing power of many countries, contributing to an economic recovery. In addition, a weaker U.S. dollar has reduced the overall revenue of OPEC countries, which may have required them to manage to a higher WTI benchmark price. During 2003 oil reached a high of US$39.25 on February 27, 2003, and a low of US$25.22 on April 29, 2003, closing out the year at US$32.52/bbl.

The forward market for crude oil indicates continued strength in prices over the next four quarters. U.S. crude oil inventories were at record low levels as we entered 2004. At the OPEC meeting on February 9th, 2004 the cartel announced its intention to reign in overproduction by some of its members and to cut quotas by a further 1 mmbbls/day on April 1, 2004. Unless they are successful in this new initiative, it is expected that the current level of output from OPEC will be sufficient to begin to build inventories by the end of the first quarter and into the second quarter of 2004 which could result in a slight reduction of WTI pricing compared to current levels. However, given the global economic recovery currently underway, oil demand is expected to continue to increase in 2004. This additional demand, combined with continued geopolitical unrest in many of the significant producing nations referred to above, leaves oil prices vulnerable to any supply disruptions and the associated high pricing scenario as experienced in 2003.

PrimeWest's greater natural gas weighting makes its revenues less susceptible to volatility in crude oil prices as compared to companies with a higher crude oil weighting.

Natural Gas Prices – Natural gas prices increased approximately 65% from a 2002 average of $4.07/mcf to an average of $6.70/mcf during 2003. Natural gas prices rose significantly during the first quarter of 2003 reaching a high of over $9.00/mcf at AECO on a one month, forward spot basis due to very cold weather conditions in the consuming areas of the U.S. during February and March that resulted in natural gas shortages. This late winter cold weather resulted in record low natural gas storage levels in the U.S. and Canada at the end of the winter heating season. Natural gas prices maintained strength through the remainder of 2003 as storage owners, which includes local distribution companies, purchased natural gas to ensure adequate storage levels for the November 2003 to March 2004 winter heating season.

As the industry entered the winter heating season in November, storage levels returned to normal levels. However, due to the early cold weather that was experienced in the major U.S. Northeast market area during December, combined with the recent experience of low storage levels the previous year, the market continued to purchase spot natural gas at relatively high prices in order to manage the storage inventories.

The high natural gas price environment in 2003 has had the effect of reducing industrial demand while at the same time increasing industry drilling activity. However, until the rebalancing of supply and demand becomes a reality as evidenced by sustained year over year storage level increases into spring, natural gas pricing is not anticipated to drop significantly. Even in the event of softer prices during the summer of 2004, the long-term price outlook for 2005 and beyond is still very positive due to an anticipated natural gas supply delivery shortfall from conventional sources.

Sales Revenue

Revenue ($ millions)	**2003**	**% of total**	2002	% of total	Change (%)
Natural gas[1]	**$ 297.3**	**68**	$ 187.7	59	58
Crude oil	**100.5**	**23**	113.1	35	(11)
Natural gas liquids	**36.8**	**9**	19.7	6	87
Total	**$ 434.6**		$ 320.5		36
Hedging (loss)/gains included above[2]	**$ (30.5)**		$ 28.1		(209)

[1] Includes sulphur.
[2] Net of amortized premiums.

Revenues for 2003 were $434.6 million compared to $320.5 million in the previous year, including the effect of hedging. Higher natural gas sales volumes as a result of the Caroline/Peace River Arch acquisition completed in January 2003 along with higher crude oil and natural gas liquids prices were the major contributors to the increased revenue in 2003.

Revenues are impacted by commodity prices, production volumes, and currency exchange rates. The strength of the Canadian dollar versus its American counterpart through the last three quarters of 2003 negatively impacted the oil and

natural gas sector, including PrimeWest. Oil and gas prices are denominated in U.S. dollars, therefore, a strengthened Canadian dollar translates into lower Canadian revenue for producers.

Based on the forward markets, the outlook for commodity prices in 2004 remains robust. Since a greater portion of PrimeWest's revenues (68%) are derived from natural gas, the Trust has greater sensitivity to changes in natural gas prices than crude oil prices. Natural decline is expected to reduce production volumes, some of which is expected to be offset by development projects and any acquisition activity.

2003 Hedging Results

As part of our financial management strategy, PrimeWest uses a consistent commodity hedging approach. PrimeWest's hedging program delivered gains of $37.1 million over the three year period from January 1, 2001 to December 31, 2003. Hedging is an important element in PrimeWest's financial management strategy. It is designed to reduce commodity price volatility, increase cash flow stability and protect the economics of acquisitions. The hedging policy reflects a willingness to forfeit a portion of the pricing upside in return for protection against a significant downturn in prices.

	Crude Oil ($/bbl)		Natural Gas ($/mcf)		BOE ($/BOE)[1]	
	2003	2002	**2003**	2002	**2003**	2002
Unhedged price	**$ 36.55**	$ 34.25	**$ 6.51**	$ 3.81	**$ 38.14**	$ 26.61
Hedge gain/(loss)	**(2.61)**	(0.72)	**(0.46)**	0.74	**(2.51)**	2.55
Realized price	**$ 33.94**	$ 33.53	**$ 6.05**	$ 4.55	**$ 35.63**	$ 29.16

[1] Excludes sulphur.

	2003 Hedge Gain (Loss)		2002 Hedge Gain (Loss)	
	% Hedged	$ millions	% Hedged	$ millions
Crude oil	**65**	**$ (7.7)**	71	$ 30.5
Natural gas	**61**	**(22.8)**	69	(2.4)
Total gain		**$ (30.5)**		$ 28.1

The following table shows approximate percentage of future anticipated production volumes hedged at December 31, 2003, net of anticipated royalties, reflecting full production declines with no offsetting additions:

2004	Q1	Q2	Q3	Q4	Full Year
Crude oil	66%	60%	48%	41%	54%
Natural gas	66%	44%	46%	17%	43%
2005					
Crude oil	9%	9%	0%	0%	5%

The mark-to-market valuation of hedges in place as at December 31, 2003 was a $6.0 million loss consisting of a $3.9 million loss in crude oil and a $2.1 million loss in natural gas.

A summary of contracts in place as at December 31, 2003 is available under Note 13 in the Notes to the Consolidated Financial Statements, reproduced later in this annual report.

Royalties (Net of ARTC)

Royalties are paid by PrimeWest to the owners of mineral rights with whom PrimeWest holds leases. PrimeWest has mineral leases with the Crown (Provincial and Federal Governments), freeholders (individuals or other companies) and other operators. ARTC is the Alberta Royalty Tax Credit, a tax rebate provided by the Alberta government to producers that paid eligible Crown royalties in the year.

($ millions, except per BOE)	2003	2002	Change (%)
Royalty expense (net of ARTC)	**$ 101.9**	$ 56.5	80
Per BOE	**$ 8.38**	$ 5.13	63
Royalties as percent of sales revenues			
With hedge revenue	**24%**	18%	33%
Excluding hedge revenue	**22%**	19%	16%

Royalty expense in 2003 was 80% higher than in 2002 due to higher crude oil and natural gas prices year-over-year. Royalties are calculated on a sliding scale based on commodity prices. As commodity prices increase, so do royalty rates.

Since hedging gains do not attract royalties and result in lower royalty expense as a percentage of sales, the hedging gains realized in 2002 contributed to the lower royalty rate.

As a percent of sales revenue, royalties were 16% higher in 2003 compared to 2002.

Royalty rates are based on commodity prices so future changes to prices will be accompanied by changes in royalty rates and royalty expense.

Operating Expenses

($ millions, except per BOE)	2003	2002	Change (%)
Operating expense	$ 79.4	$ 60.8	31
Per BOE	$ 6.53	$ 5.52	18

In general, as natural gas prices rise, power costs also increase. In 2003, PrimeWest's power cost increased by $2.8 million ($0.23/BOE). However, PrimeWest's natural gas weighting gives a natural hedge to rising power costs. Further, PrimeWest engaged in heat rate swaps, and recovered $0.5 million in protection ($0.04/BOE) reducing the power cost, resulting in a net increase in power expense of $2.3 million ($0.19/BOE).

Operating expenses for 2003 were $18.6 million higher than 2002. On a per BOE basis operating expenses increased 18% over the 2002 level. A primary contributor to the increase in operating expenses during 2003 was the increased volumes and resulting operating cost of $6.7 million associated with the Caroline/Peace River Arch acquisition which closed in January 2003.

Operating Expenses ($/BOE)

Increased operating expenses for 2003 include prior period adjustments in the form of equalization fees PrimeWest incurred to cover the costs associated with processing more production volumes than allotted at a shared production facility. These increased equalization fees totaled $2.3 million ($0.19/BOE). Field consulting and contracting expenses totaled $1.4 million ($0.12/BOE) and were attributed to a field level restructuring undertaken in 2003 which is expected to reduce ongoing field staff costs by 20%. Well workovers and repairs during 2003 added an additional $1.9 million ($0.16/BOE) to operating expenses and in addition, non-operated property expenses for 2003 were $2.5 million higher than the 2002 costs.

Operating expenses are primarily impacted by labor and power expenditures which represent approximately 30% of PrimeWest's costs. In addition, partner-operated expenses, along with property taxes and lease rentals, make up approximately 24% of our costs, which are difficult to influence. PrimeWest is targeting 2004 operating expenses at approximately $6.75/BOE. Cost control will be undertaken by maintaining control of operations wherever possible.

Operating Margin

($/BOE)	2003	2002	Change (%)
Sales price and other revenue[1]	$ 35.52	$ 29.11	22
Royalties	(8.38)	(5.13)	63
Operating expenses	(6.53)	(5.52)	18
Operating margin	$ 20.61	$ 18.46	12

[1] Includes hedging and sulphur.

Operating margins increased 12% from 2002 on a per BOE basis. The increase in 2003 compared to 2002 is primarily due to higher sales prices, offset by higher operating expenses and higher royalties. Operating margin is an important measure of our business because it gives an indication of how much money PrimeWest makes per BOE that is produced.

Operating Margin ($/BOE)

Based on PrimeWest's commodity price outlook, operating expense expectations and hedge positions, margins are expected to be lower in 2004 than 2003. However, this will be heavily dependent on actual commodity prices. PrimeWest will continue to emphasize maintaining lower than average operating expenses to maximize margins, which can reduce the volatility of cash flows through commodity price cycles.

General and Administrative Expense

($ millions, except per BOE)	2003	2002	Change (%)
Cash general and administrative expense	$ 14.5	$ 11.3	28
Per BOE	$ 1.20	$ 1.02	18
Non-cash general and administrative expense	$ 14.4	$ 6.1	136
Per BOE	$ 1.19	$ 0.55	116

Cash general and administrative expense increased 28% in 2003 from 2002, primarily due to higher recruitment costs, staff levels, short-term incentive payments and salary payments totaling approximately $2.6 million ($0.21 /BOE). In addition, one-time costs associated with international business development activities of $0.4 million were incurred in 2003. We anticipate that 2004 general and administrative expense will be reduced on a dollar basis due to the elimination of international business development activities, a one-time evaluation cost.

Non-cash general and administrative expense consists mainly of the change in the value of the Unit Appreciation Rights (UARs). Unit Appreciation Rights in a trust are similar to stock options in a corporation. Consistent with the resolution approved by Unitholders at the last annual meeting of Unitholders, PrimeWest continues to pay for the exercise of UARs in trust units. The intent of PrimeWest's UAR plan is to align employee and Unitholder interests.

Of the $14.4 million in non-cash general and administrative expense, $13.9 million pertained to UARs. This compares to $6.1 million in 2002 and is attributable to PrimeWest's 28% total return to Unitholders in 2003 (2002 – 19.5%), along with ongoing employee UAR grants to ensure PrimeWest remains competitive in attracting and retaining quality staff. The program rewards employees based on total Unitholder return, which is comprised of cumulative distributions on a reinvested basis plus growth in unit price. No benefit accrues to employees who hold UARs until the Unitholders have first achieved a 5% total annual return from the time of grant. Expenses related to the UAR plan are recorded on a mark-to-market basis, whereby increases or decreases in the valuation of the UAR liability are reported quarterly, as a charge to the income statement.

Management Fees/Internalization

($ millions)	**2003**	2002
Cash management fees	–	$ 4.0
Non-cash management fees	–	1.4
Non-cash internalization costs	–	13.1
Acquisition/disposition fees	–	0.4
1% retained royalty	–	1.3
Purchase of 1% retained royalty	–	13.2
	–	$ 33.4

On November 4, 2002, Unitholders voted by a 92% majority to internalize management at a cost of $26.3 million. The management internalization was an important change for PrimeWest and benefited Unitholders for several reasons. The internalization was accretive to NAV and cash flow in 2003 and improved the long-term cost structure of the Trust. Further, it more appropriately aligned management interests with Unitholders, and resulted in Unitholders having the ability to elect all of the directors of the Trust.

Interest Expense

($ millions, except per trust unit)	2003	2002	Change (%)
Interest expense	$ 15.1	$ 10.8	40
Period end net debt level	$ 255.9	$ 225.7	13
Debt per trust unit	$ 5.07	$ 5.75	(12)
Average cost of debt	4.7%	4.6%	2

Interest expense, representing interest on bank debt, increased to $15.1 million from $10.8 million in 2002 due to higher average debt balances in 2003 compared to 2002.

In 2003, PrimeWest diversified its debt financing by completing a private placement of US$125 million at a U.S. fixed coupon rate of 4.19%. The actual Canadian interest expense will fluctuate with any changes in the Canadian/U.S. foreign exchange rates. Canadian interest rates are expected to decline in 2004, as the Bank of Canada has reduced its overnight rate by 25 basis points on January 20, 2004. Additional Bank of Canada rate reductions are anticipated later in 2004.

Foreign Exchange Gain

The foreign exchange gain of $11.9 million results from the translation of the U.S. dollar-denominated secured notes and related interest payable. The notes were issued at 1.3923:1 Canadian to U.S. dollars, and the close rate on December 31, 2003 was 1.2965:1 Canadian to U.S. dollars.

Depletion, Depreciation and Amortization

The 2003 DD&A rate of $16.70/BOE is higher than the full year 2002 rate of $16.51/BOE due to 2003 acquisitions.

The 2002 and 2003 DD&A rates are inflated relative to the acquisition cost of certain reserves due to the requirement to account for future income tax liabilities associated with the acquisition of those reserves. The offset is in the income tax recovery. Without this tax adjustment, the DD&A rate would be lower by approximately $3.14/BOE in 2003 (2002 – $3.62/BOE).

Ceiling Test

PrimeWest performs a ceiling test at each balance sheet date, which compares the net book value of capital assets (i.e. the value of capital assets reflected on the balance sheet, net of DD&A) with an estimate of the future net revenue from Proved reserves (as determined by independent engineers), less estimated future general and administrative costs, debt servicing costs, and applicable income taxes.

Performing this test at December 31, 2003, using commodity prices as at December 31, 2003 of AECO $6.09/mcf for natural gas and US$32.52/bbl WTI for crude oil results in a ceiling test surplus. The new CICA Accounting Guideline 16 was introduced in 2003 (for additional details see Accounting Pronouncements Issued but not Implemented later in this release). The impact of this new guideline on the Trust would be an impairment to capital assets of approximately $460 million before tax or approximately $297 million after tax. The after-tax impairment of $297 million will be booked to retained earnings in the first quarter of 2004.

Site Reclamation and Restoration Reserve

Since the inception of the Trust, PrimeWest has maintained an environmental fund to pay for future costs related to well abandonment and site clean-up. In 2003, PrimeWest contributed $0.50/BOE, totaling $6.2 million for 2003, to this fund. A provision of $4.2 million was made for site reclamation and abandonment during 2003, compared to $4.0 million for 2002. The provision is based on site reclamation and abandonment cost estimates made by both PrimeWest and external engineers and is charged to depletion, depreciation and amortization expense on a unit-of-production basis.

An additional contribution of $4.2 million was made to fund reclamation expenditures associated with properties acquired in 2002. The fund is used to pay for reclamation and abandonment costs as they are incurred. In 2003, a total of $2.2 million was paid out of the reserve, leaving a balance of $8.2 million in the fund at year end.

The 2004 contribution rate has been maintained at $0.50/BOE which is expected to be sufficient to meet the funding requirements for the future.

Net Asset Value

Net asset value (NAV) is a measure of the worth of PrimeWest's underlying assets – primarily crude oil, natural gas and natural gas liquids reserves. The value placed on these reserves is the pre-tax present value of future net cash flows, discounted at 10% from these reserves, as independently assessed by GLJ as at January 1, 2004. Two commodity price forecasts were used in this assessment. The first forecast is based on the arithmetic average of three independent consultants' price forecasts. The second forecast is the forward oil and natural gas prices as of February 5th, 2004. The present value of reserves reflects provisions for royalties, operating costs, future capital costs and site reclamation and abandonment costs, but is prior to deductions for income taxes, interest costs and general and administrative costs.

This calculation is a "snapshot" in time and is heavily dependent upon future commodity price expectations at the point in time the "snapshot" is taken. Accordingly, the NAV as at January 1, 2004 may not reflect fairly the equity market trading value of PrimeWest. It is also significant to note that NAV reduces as reserves are produced and net operating cash flow is distributed. Value is delivered to Unitholders through such monthly distributions.

The following table sets forth the calculation of NAV:

As at December 31 ($ millions, except per trust unit amounts)	**2003 Consultant's Average**	Feb 5th Forward Strip	2002 Consultant's Average
Assets			
PV_{10} of future cash flow[1]	**$ 904.6**	$ 1,036.5	$ 923.0
Mark-to-market value of hedging contracts	**(0.5)**	(6.0)	(13.6)
Unproved lands	**36.0**	36.0	44.2
Reclamation fund	**8.2**	8.2	–
	948.3	1,074.7	953.6
Liabilities			
Debt and working capital deficiency	**(255.9)**	(255.9)	(225.7)
Net Asset Value	**$ 692.4**	$ 818.8	$ 727.9
Outstanding trust units – millions, fully diluted	**50.4**	50.4	39.3
NAV per trust unit	**$ 13.74**	$ 16.25	$ 18.52

100% of Proved and Probable reserves for 2003; 100% of Established reserves for 2002.

Pricing assumptions	**2003 Consultant's Average**	Feb 5th Forward Strip	2002 Consultant's Average
Edmonton Par Oil – Cdn$/bbl			
2004	**$ 37.81**	$ 40.11	$ 34.41
2005	**$ 34.10**	$ 36.81	$ 32.14
2006	**$ 32.79**	$ 35.63	$ 32.09
2007	**$ 32.72**	$ 35.26	$ 32.53
2008	**$ 32.89**	$ 35.19	$ 33.11
Spot Gas at AECO-C – Cdn$/mcf			
2004	**$ 5.90**	$ 6.23	$ 5.13
2005	**$ 5.33**	$ 6.02	$ 4.76
2006	**$ 4.98**	$ 5.64	$ 4.70
2007	**$ 4.95**	$ 5.44	$ 4.76
2008	**$ 4.92**	$ 5.36	$ 4.79

The NAV calculation is based on the above referenced prices as of December 31, 2003 and 2002 and is highly sensitive to changes in price forecasts over time as well as the exchange rate. In addition, the year-over-year change is impacted by the cash distributions made throughout the year which totaled $192.6 million or $4.32 per unit. Also, the NAV calculation assumes a "blow down" scenario whereby existing reserves are produced without being replaced by acquisitions. A major cornerstone of PrimeWest's strategy is to replace reserves through accretive acquisitions and capital development.

Income and Capital Taxes

($ millions)	2003	2002	Change (%)
Income and capital taxes	$ 3.8	$ 2.9	31
Future income taxes recovery	(83.0)	(32.3)	157
	$ (79.2)	$ (29.4)	169

On June 9, 2003 the Canadian Government substantially enacted Federal income tax changes for the oil and natural gas resource sector as outlined in its 2003 budget. The Federal income tax changes effectively reduced the statutory tax rates for current and future periods, resulting in a significant increase in the future tax recovery (a non-cash item) compared to the first quarter of 2003 and prior years. Specifically, the current 100% deductibility of the resource allowance will be completely phased out by the year 2007. During the same time-frame, Crown charges will become 100% deductible and resource tax rates will decline from the current 27% to 21%.

Net Income

($ millions)	2003	2002
Net income	$ 90.3	$ 0.6

Cash flow from operations, as opposed to net income, is the primary measure of performance for an energy trust. The generation of cash flow is critical to the ability of an energy trust to continue to sustain the monthly distribution of cash to Unitholders.

Conversely, net income is an accounting measure impacted by both cash and non-cash items. The largest non-cash items impacting PrimeWest's net income are depletion, depreciation, and amortization (DD&A) and future taxes. The future tax figure has been significantly impacted by changes to statutory tax rates during the second quarter of 2003.

Net income for 2003 was impacted by higher sales revenue as a result of higher commodity prices and volumes compared to 2002. In addition, future income tax recoveries and non-cash foreign exchange gains contributed approximately $95 million to net income in 2003.

Liquidity and Capital Resources

Long-Term Debt

($ millions)	2003	2002	Change (%)
Long-term debt	$ 250.1	$ 225.0	11
Working capital deficit	5.8	0.7	729
Net debt	$ 255.9	$ 225.7	13
Market value of trust units and Exchangeable shares outstanding[1]	1,380.7	989.2	40
Total capitalization	$ 1,636.6	$ 1,214.9	35
Net debt as a percent of total capitalization	16%	19%	(16)

[1] Based on December 31 trust unit closing price of $27.56 and exchangeable ratio of 0.44302:1.

Long-term debt is comprised of bank credit facilities and senior secured notes for $88.0 million and $162.1 million, respectively. PrimeWest had a borrowing base of $390 million at year end 2003. The bank credit facilities consist of a revolving term loan of $188 million and an operating facility of $25 million. In addition to amounts outstanding under the facility, PrimeWest has outstanding letters of credit in the amount of $5.1 million (2002 – $3.8 million). The credit facility revolves until June 30, 2004 by which time the lenders will have conducted their annual borrowing base review.

Debt to Annual Cash Flow Multiple

On May 7, 2003 PrimeWest replaced a portion of its bank debt with Senior Secured Notes in the amount of US$125 million. The notes have a final maturity date of May 7, 2010 and bear interest at 4.19% per annum, with interest paid semi-annually on November 7 and May 7 of each year. The Note Purchase Agreement requires PrimeWest to make four annual principal repayments of US$31,250,000 commencing May 7, 2007.

Being in a cyclical business, it is important that PrimeWest maintains financial flexibility to ensure we can operate without any restrictions regardless of where commodities are in the price cycle. PrimeWest's objective is to have conservative debt levels. Our internal targets are to keep debt at two times or less than our annual cash flow and less than 25% of enterprise value. For 2003, PrimeWest's debt to cash flow was 1.2 times, and at year end, was 16% of our total enterprise value. In 2003, PrimeWest expanded its debt financing strategy by undertaking the U.S. private placement and thus reducing its total dependence on bank financing. In addition, PrimeWest moved to a lower payout ratio, thus using internally-generated cash to invest in development opportunities or pay down bank debt.

Unitholders' Equity

The Trust had 48,751,883 trust units outstanding at December 31, 2003 compared to 37,004,522 trust units at the end of 2002. In addition, there are 3,041,123 Exchangeable shares (see page 56) outstanding at year end, exchangeable into a total of 1,347,277 trust units. The weighted average number of trust units, including those issuable by the exchange of Exchangeable shares, was 46,015,519 trust units for 2003 compared to 34,135,576 for 2002.

During the year, 360,608 trust units were issued pursuant to the Unit Appreciation Rights Plan for employees.

During the year, PrimeWest completed two bought-deal financings. The first closed on February 13, 2003 raising net proceeds of $146.6 million on the issuance of 6 million trust units at $25.75 per trust unit. Proceeds were used to reduce the indebtedness of PrimeWest under its credit facility, including a portion incurred in connection with the January 2003 acquisition of two private Canadian exploration and production companies with properties in the Caroline and Peace River Arch areas of Alberta. The second financing closed on September 26, 2003 raising net proceeds of $76.1 million on the issuance of 3.1 million trust units at $25.90 per trust unit. Proceeds were used to reduce bank indebtedness and pursue development opportunities in the Caroline, Valhalla and Brant/Farrow areas.

Trust Units Outstanding at Year End (millions)

Under the Distribution Reinvestment Plan, PrimeWest issued 465,969 trust units for $11.4 million pursuant to the Distribution Reinvestment component (2002 – 476,106 trust units, for $10.1 million); 134,629 trust units for $3.4 million pursuant to the Premium Distribution component (2002 – 0 trust units); and 721,209 trust units for $17.6 million pursuant to the Optional trust unit Purchase Plan component (OTUPP) in 2003 (2002 – 503,103 trust units for $13.9 million).

For the first time in PrimeWest's history, the OTUPP sold out before the end of the calendar year, demonstrating the strong support of existing Unitholders. During the fourth quarter, PrimeWest enhanced its existing plan with the Premium Distribution (PREP) component.

As an alternative to the existing DRIP component of the Plan, the new PREP allows eligible Canadian Unitholders to elect to receive a premium cash distribution of up to 102% of the cash that the Unitholder would otherwise have received on the distribution date, subject to proration in certain events.

The DRIP gives Canadian Unitholders the chance to reinvest their monthly distributions at a 5% discount to the volume weighted average market price, while the OTUPP gives Canadian Unitholders an opportunity to purchase

additional trust units directly from PrimeWest at the same 5% discount to the volume weighted average market price. The DRIP and PREP components are mutually exclusive, and participation in the OTUPP requires enrollment in either the DRIP or PREP.

These plan components benefit the Unitholders by offering alternatives to maximize their investment in PrimeWest, while providing the Trust with an inexpensive method to raise additional capital. The Trust expects interest in these plans in 2004 to be similar to 2003. Proceeds from these plans are used for debt reduction of PrimeWest's credit facility and to help fund ongoing capital development programs.

In 2003 PrimeWest completed a review of the requirements necessary for the establishment of a U.S. DRIP program and concluded that such a program for U.S. resident Unitholders is not presently feasible.

For additional information or to join these plans, contact PrimeWest's Plan Agent, Computershare Trust Company of Canada at 1-800-564-6253 or visit PrimeWest's website at www.primewestenergy.com.

Exchangeable Shares

Exchangeable shares were issued in connection with both the Venator Petroleum Company Ltd. acquisition in April 2000 and the Cypress Energy Inc. acquisition in March 2001. These shares were issued to provide a tax-deferred rollover of the adjusted cost base from the shares being exchanged by the shareholders of the acquired companies to the Exchangeable shares of PrimeWest. A tax deferral is not permitted by Canadian tax law when shares are exchanged for trust units.

In 2002, 1,363,714 Exchangeable shares were issued in connection with the management internalization transaction. During 2003, 1,500,000 Exchangeable shares were issued in relation to the termination of the management incentive program of PrimeWest Management Inc. (See Note 11 in the Consolidated Financial Statements).

The Exchangeable shares do not receive cash distributions. In lieu of receiving cash distributions, the number of trust units that the exchangeable shareholder will receive upon exchange increases each month based on the distribution amount divided by the market price of the trust units on the 15th day of each month.

At December 31, 2003 there were 3,041,123 Exchangeable shares outstanding. The exchange ratio on these shares was 0.44302 trust units for each exchangeable share as at year end.

For purposes of calculating basic per trust unit amounts, these Exchangeable shares have been assumed to be exchanged into trust units at the current exchange ratio.

Cash Distributions

Cash distributions to Unitholders are at the discretion of the Board of Directors and can fluctuate depending on the cash flow generated from operations. As discussed previously, the cash flow available for distribution is

dependent upon many factors including commodity prices, production levels, debt levels, capital spending requirements and factors in the overall environment.

In 2003 cash distributions totaled $192.6 million or $4.32 per trust unit, compared to $158.0 million or $4.80 per trust unit in 2002. Since inception in October 1996 to December 31, 2003 PrimeWest has distributed $40.24 per trust unit – just over the initial public offering price of $40.00 (through December 31, 2002 – $35.92 per trust unit). In June 2003 PrimeWest's Board of Directors announced its intention to distribute 70-90% of cash flow, as opposed to the Trust's historical 95% average annual payout ratio. Withholding some internally-generated cash increases PrimeWest's financial flexibility.

Payments to U.S. Unitholders are subject to 15% Canadian withholding tax, which applies to the taxable portion of the distribution.

Cash Flow Sensitivities

The table below is designed to provide the directional impact on 2004 annual cash available for distribution per unit (increase/decrease) depending on changes in the following:

	$/Trust Unit[1]
Crude oil price (US$1.00/bbl WTI increase)	0.07
Natural gas price ($0.10/mcf increase)	0.06
Exchange rate (US$0.01 decrease)	0.07
Interest rate (1% decrease)	0.01
Production (1,000 BOE/day increase)	0.14

[1] Without the effect of price protection.

The figures in this table are provided for directional information only and are based on the units outstanding as at December 31, 2003. Should changes to commodity price, interest rate, exchange rate or production levels noted above take place, it should not be assumed that a corresponding change would be made to the distribution level.

Contractual Obligations

PrimeWest enters into many contract obligations as part of conducting day-to-day business. Material contract obligations that PrimeWest has currently in place are lease rental commitments that run from 2004 through 2009 and require annual payments after deducting sub-lease income of $1.2 million in 2004, $1.1 million in 2005 and 2006, and $2.4 million in 2007 through 2009, the remaining term of the lease. In addition, PrimeWest also has a pipeline transportation commitment that runs to October 31, 2007 and has minimum annual payment requirements of US$2.1 million.

As part of PrimeWest's internalization transaction (see Note 11 in the Consolidated Financial Statements), PrimeWest agreed to pay $3.5 million in Exchangeable shares pursuant to a special employee retention plan. One quarter of the Exchangeable shares will be issuable to the Senior Officers of PrimeWest on each of the second, third, fourth and fifth anniversary of transaction closing, November 6, 2002. As at December 31, 2003 $0.5 million has been accrued in non-cash general and administrative expenses related to the special employee retention plan.

Recent Accounting Pronouncements (issued but not implemented)

During 2003, the following new or amended standards and guidelines were issued:

Hedging Transactions

The CICA has issued Accounting Guideline 13, Hedging Relationships, (AcG 13) which will be effective for fiscal years beginning on or after July 1, 2003. AcG 13 addresses the identification, designation, documentation and effectiveness of hedging transactions for the purposes of applying hedge accounting. It also establishes conditions for applying or discontinuing hedge accounting. Under the new guideline, hedging transactions must be documented and it must be demonstrated that the hedges are sufficiently effective in order to continue accrual accounting for positions hedged with derivatives. The Trust does not anticipate applying hedge accounting to its hedging relationships.

Asset Retirement Obligations

In March 2003, the CICA issued a new section in the CICA Handbook, section 3110, Asset Retirement Obligations. This standard focuses on the recognition and measurement of liabilities related to legal obligations associated with the retirement of property, plant and equipment. Under this standard, these obligations are initially measured at fair value and subsequently adjusted for the accretion of discount and any changes in the underlying cash flows. The asset retirement cost is to be capitalized to the related asset and amortized into earnings over time. This section comes into effect for the Trust in 2004. The Trust is currently evaluating the impact of this standard on its consolidated financial statements and does not anticipate it will have a material impact.

Oil and Natural Gas Assets – Full Cost Accounting

In 2003, the CICA issued Accounting Guideline 16 impacting the application of the cost centre impairment test (ceiling test). The guideline is effective for fiscal years beginning on or after January 1, 2004. The cost impairment test is now a two-stage process which is to be performed at least annually. The first stage of the test determines if the cost pool is impaired. An impairment loss exists when the carrying amount of an asset is not recoverable and exceeds its fair value. The carrying amount is not recoverable if it exceeds the sum of the undiscounted cash flows from Proved reserves plus unproved costs using management's best estimate of future prices. The second stage determines the amount of the impairment loss to be recorded. The impairment is measured as the amount by which the carrying amount of capitalized assets exceeds the future discounted cash flows from Proved plus

Probable reserves. The discount rate used is the Company's risk-free rate. The guideline requires disclosure of the prices used for purposes of the impairment test.

The impact of this new guideline on the Trust would be an impairment to capital assets of approximately $460 million before tax or approximately $297 million after tax. The after-tax impairment of $297 million will be booked to retained earnings in the first quarter of 2004.

Exchangeable Share Accounting

In November 2003 the CICA issued a draft EIC (D37) on Income Trusts – Exchangeable Units. The EIC proposes that the retained interest of the exchangeable shareholders should be presented on the balance sheet as a non-controlling interest separate and distinct from Unitholder's equity. This draft EIC is currently under review and was not enacted in final form as of the time of publication of the Trust's consolidated financial statements.

Variable Interest Entities

In June 2003 the CICA issued Accounting Guideline 15 Consolidation of Variable Interest Entities which deals with the consolidation of entities that are subject to control on a basis other than ownership of voting interests. This guideline is effective for annual and interim periods beginning on or after November 1, 2004. The Trust has assessed that this new guideline is not applicable based on the current structure of the Trust and therefore will have no impact on the financial statements of the Trust.

Business Risks

PrimeWest's operations are affected by a number of underlying risks, both internal and external to the Trust. These risks are similar to those affecting others in both the conventional oil and gas royalty trust sector and the conventional oil and gas producers sector. The Trust's financial position, results of operations, unit price and cash available for distribution to Unitholders are directly impacted by these factors. These factors are discussed under two broad categories – Commodity Price, Foreign Exchange and Interest Rate Risk; and Operational and Other Business Risks.

Commodity Price, Foreign Exchange and Interest Rate Risk

The two most important factors affecting the unit price and level of cash distributions available to Unitholders are the level of production achieved by PrimeWest, and the price received for its products. These prices are influenced in varying degrees by factors outside of the Trust's control. Some of these factors include:

- World market forces, specifically the actions of OPEC and other large crude oil producing countries including Russia, and their implications on the supply of crude oil;
- World and North American economic conditions which influence the demand for both crude oil and natural gas and the level of interest rates set by the governments of Canada and the U.S.;

- Weather conditions that influence the demand for natural gas and heating oil;
- The Canadian/U.S. exchange rate that affects the price received for crude oil as the price of crude oil is referenced in U.S. dollars;
- Transportation availability and costs; and
- Price differentials among world and North American markets based on transportation costs to major markets and quality of production.

To mitigate these risks, PrimeWest has an active hedging program in place based on an established set of criteria that has been approved by the Board of Directors. The results of the hedging program are reviewed against these criteria and the results actively monitored by the Board.

Beyond our hedging strategy, PrimeWest also mitigates risk by having a well-diversified marketing portfolio and by transacting with a number of counter-parties and limiting exposure to each counter party. In 2003, approximately 25% of natural gas production was sold to aggregators and 75% into the Alberta short-term or export long-term markets.

The contracts that PrimeWest has with aggregators vary in length. They represent a blend of domestic and U.S. markets and fixed and floating prices designed to provide price diversification to our revenue stream.

The primary objective of our commodity risk management program is to reduce the volatility of our cash distributions, to lock in the economics on major acquisitions and to protect our capital structure when commodity prices cycle downwards. In 2003, PrimeWest lost $30.5 million from commodity hedges ($0.66 per trust unit), while in 2002, PrimeWest added $28.1 million ($0.82 per trust unit) to our cash flow through various physical and financial hedging transactions. Over the three-year period 2001 to 2003, PrimeWest's hedging program has added $37.1 million to revenue.

Operational and Other Business Risks

PrimeWest is also exposed to a number of risks related to its activities within the oil and gas industry that have an impact on unit price and the amount of cash available to Unitholders. These risks, and the ways in which PrimeWest seeks to mitigate them include, but are not limited to those outlined in the following table:

RISK	MITIGATED BY
Production Risk associated with the production of oil and natural gas – includes well operations, processing and the physical delivery of commodities to market.	Performing regular and proactive protective well, facility and pipeline maintenance supported by telemetry, physical inspection and diagnostic tools.
Commodity price Fluctuations in natural gas, crude oil and natural gas liquid prices.	Hedging. See page 45 of this Annual Report.

RISK	MITIGATED BY
Transportation Market risk related to the availability of transportation to market and potential disruption in delivery systems.	Diversifying the transportation systems on which we rely to get our product to market.
Natural decline Development risk associated with capital enhancement activities undertaken – the risk that capital spending on activities such as drilling, well completions, well workovers and other capital activities will not result in reserve additions or in quantities sufficient to replace annual production declines.	Diversifying our capital spending program over a large number of projects so that too much capital is not risked on any one activity. We also have a highly skilled technical team of geologists, geophysicists and engineers working to apply the latest technology in planning and executing capital programs. Capital is spent only after strict economic criteria for production and reserve additions are assessed.
Acquisitions Acquisition risk associated with acquiring producing properties at low cost to renew our inventory of assets.	Continually scanning the marketplace for opportunities to acquire assets. Our technical acquisition specialists evaluate potential corporate or property acquisitions and identify areas for value enhancement through operational efficiencies or capital investment. All prospects are subjected to rigorous economic review against established acquisition and economic hurdle rates. In some cases we may also hedge commodity prices to protect the acquisition economics in the near-term period.
Reserves Reserve risk in respect of the quantity and quality of recoverable reserves.	Contracting our reserves evaluation to a reputable third-party consultant, GLJ. The work and independence of GLJ is reviewed by the Audit and Reserves Committee of the Board of Directors of PrimeWest. Our strategy is to invest in mature, longer-life properties having a higher proved producing component where the reserve risk is generally lower and cash flows are more stable and predictable.
Environment, health and safety (EH&S) Environmental, health and safety risks associated with oil and natural gas properties and facilities.	Establishing and adhering to strict guidelines for EH&S including training, proper reporting of incidents, supervision and awareness. PrimeWest has active community involvement in field locations including regular meetings with stakeholders in the area. PrimeWest carries adequate insurance to cover property losses, liability and business interruption. These risks are reviewed regularly by the Corporate Governance and Nominating Committee of the Board, which acts as PrimeWest's Environmental, Health and Safety Committee.
Regulation, tax, royalties Changes in government regulations including reporting requirements, income tax laws, operating practices and environmental protection requirements and royalty rates.	Keeping informed of proposed changes in regulations and laws to properly respond to and plan for the effects that these changes may have on our operations.
Liability to Unitholders There is no statutory protection for Unitholders from liabilities of the Trust.	Limiting the business of the Trust to the right to receive the net cash flow of PrimeWest Energy Inc. All of the oil and natural gas business operations of PrimeWest are conducted by PrimeWest Energy Inc. PrimeWest Energy Inc. has a vigorous EH&S program as well as significant insurance protection.

Income Taxes – Unitholders – 2003

For the 2003 taxation year, Canadian Unitholders of PrimeWest were paid Cdn$4.40 per trust unit in distributions. Of this distribution amount, 42% or $1.85 per trust unit is deemed a tax-deferred return of capital, and 58% or $2.55 per trust unit is taxable to Unitholders as other income (taxed at the same rate as interest income).

For Unitholders resident in the U.S., the taxability of distributions is calculated using U.S. tax rules which allow for the deduction of Crown royalties and accounting-based depletion. As a result of these deductions, none of the 2003 distribution is taxable as dividends and 100% of the 2003 distributions are a tax-deferred return of capital. A 15% withholding tax applies to distributions paid to U.S. Unitholders. Further details regarding the withholding tax are available on PrimeWest's website at www.primewestenergy.com.

For both Canadian and U.S. Unitholders, the tax-deferred return of capital portion reduces the Unitholder's adjusted cost base for purposes of calculating a capital gain or loss upon ultimate disposition of their trust units. Unitholders contemplating a disposition may wish to consult the "Unitholder Info" section on PrimeWest's website and use the adjusted cost base calculator.

Quarterly Performance

	2003				2002			
($ millions except per trust unit amounts)	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4
Net revenues	**94.0**	**85.6**	**77.3**	**73.0**	69.4	62.3	63.8	68.8
Net income	**22.0**	**61.6**	**7.4**	**(0.7)**	5.9	(6.2)	8.2	(7.3)
Income per Unit	**0.52**	**1.35**	**0.16**	**(0.01)**	0.20	(0.20)	0.24	(0.20)

The above table highlights PrimeWest's quarterly performance for the years ended 2003 and 2002.

Net revenues were primarily impacted by higher commodity prices and production volumes in 2003. Net income was higher in 2003 as a result of foreign exchange gains along with increased tax recoveries.

Management Responsibility for Financial Statements and Management's Discussion and Analysis

The consolidated financial statements of PrimeWest Energy Trust and Management's Discussion and Analysis (MD&A) were prepared by, and are the responsibility of the management of PrimeWest Energy Inc. The consolidated financial statements have been prepared in accordance with accounting principles generally accepted in Canada. The financial and operating information presented in this annual report is consistent with that shown in the consolidated financial statements.

Management has designed and maintains a system of internal controls to safeguard assets and ensure that transactions are properly authorized and recorded and form part of these financial statements. Where estimates are used in the preparation of these financial statements, management has ensured that careful judgment has been made and that these estimates are reasonable, based on all information known at the time the estimates are made.

The Board of Directors of PrimeWest is responsible for ensuring that management fulfills its responsibilities for financial reporting, and it has reviewed and approved these financial statements and MD&A. The Board carries out this responsibility through the Audit and Reserves Committee, which consists of the independent directors of the Board.

Unitholders have appointed the external audit firm of PricewaterhouseCoopers LLP to express their opinion on the consolidated financial statements. The auditors have full and unrestricted access to the Audit and Reserves Committee to discuss their findings.

Don Garner
President and Chief Executive Officer

Dennis G. Feuchuk
Vice-President, Finance and Chief Financial Officer

February 19, 2004

Auditors' Report

To the Unitholders of PrimeWest Energy Trust:

We have audited the consolidated balance sheets of PrimeWest Energy Trust as at December 31, 2003, 2002, and 2001 and the consolidated statements of income, cash distributions, Unitholders' equity, and cash flows for the years then ended. These financial statements are the responsibility of the management of the Trust. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with Canadian generally accepted auditing standards. Those standards require that we plan and perform an audit to obtain reasonable assurance whether the financial statements are free from material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation.

In our opinion, these consolidated financial statements present fairly, in all material respects, the financial position of the Trust as at December 31, 2003, 2002 and 2001, and the results of its operations and cash flows for the years then ended, in accordance with Canadian generally accepted accounting principles.

PricewaterhouseCoopers LLP

PricewaterhouseCoopers LLP, Chartered Accountants
Calgary, Alberta
February 6, 2004

Consolidated Balance Sheets

As at December 31 (millions of dollars)	2003	2002	2001
Assets			
Current assets			
Cash and short term deposits	**$ 2.5**	$ –	$ –
Accounts receivable	**65.4**	71.6	60.6
Prepaid expenses	**6.5**	9.8	9.1
Inventory	**2.1**	2.2	3.2
	76.5	83.6	72.9
Cash reserved for site restoration and reclamation *(note 7)*	**8.2**	–	0.7
Other assets *(note 5)*	**0.2**	14.4	–
Deferred charges	**1.3**	–	–
Property, plant and equipment *(note 4)*	**1,537.6**	1,404.5	1,448.7
Goodwill *(note 3)*	**56.1**	–	–
	$ 1,679.9	$ 1,502.5	$ 1,522.3
Liabilities and Unitholders' equity			
Current liabilities			
Bank overdraft	**$ –**	$ 3.1	$ 14.6
Accounts payable	**26.7**	43.1	26.2
Accrued liabilities	**45.3**	24.2	39.4
Accrued distributions to Unitholders	**10.3**	13.9	12.0
Due to related company *(note 11)*	**–**	–	10.1
	82.3	84.3	102.3
Long-term debt *(note 6)*	**250.1**	225.0	195.0
Future income taxes *(note 12)*	**310.1**	339.9	362.6
Site restoration and reclamation provision	**17.8**	6.2	6.1
	660.3	655.4	666.0
Unitholders' equity			
Net capital contributions *(note 8)*	**1,565.9**	1,300.0	1,152.6
Capital issued but not distributed	**5.2**	0.9	1.0
Long-term incentive plan equity *(note 9)*	**14.6**	10.0	7.9
Accumulated income	**213.5**	123.2	122.6
Accumulated cash distributions	**(771.6)**	(579.0)	(421.0)
Accumulated dividends	**(8.0)**	(8.0)	(6.8)
	1,019.6	847.1	856.3
	$ 1,679.9	$ 1,502.5	$ 1,522.3

Commitments and Contingencies (Note 14)

The accompanying notes form an integral part of these financial statements.

Harold P. Milavsky
Chair of the Board of Directors

Harold N. Kvisle
Director

Consolidated Statements of Unitholders' Equity

For the years ended December 31 (millions of dollars)	**2003**	2002	2001
Unitholders' equity, beginning of year	**$ 847.1**	$ 856.3	$ 298.6
Net income for the year	**90.3**	0.6	79.5
Net capital contributions	**265.9**	147.4	717.2
Capital issued but not distributed	**4.3**	(0.1)	0.4
Long-term incentive plan equity	**4.6**	2.1	(1.0)
Cash distributions	**(192.6)**	(158.0)	(234.4)
Dividends	–	(1.2)	(4.0)
Unitholders' equity, end of year	**$ 1,019.6**	$ 847.1	$ 856.3

Consolidated Statements of Cash Flow

For the years ended December 31 (millions of dollars)	2003	2002	2001
Operating activities			
Net income for the year	$ 90.3	$ 0.6	$ 79.5
Add/(deduct):			
Items not involving cash from operations			
Depletion, depreciation and amortization	207.3	182.0	159.3
Non-cash general & administrative	14.4	6.1	4.2
Non-cash foreign exchange gain	(12.1)	–	–
Non-cash management fees	–	1.4	1.8
Non-cash internalization costs	–	13.1	–
Future income taxes recovery	(83.0)	(32.3)	(30.3)
Other non-cash items	(0.3)	–	–
Cash flow from operations	216.6	170.9	214.5
Expenditures on site restoration and reclamation	(2.2)	(3.9)	(3.7)
Change in non-cash working capital	5.3	(10.7)	(20.5)
	$ 219.7	$ 156.3	$ 190.3
Financing activities			
Proceeds from issue of Trust Units (net of costs)	$ 240.3	$ 118.3	$ 159.5
Net cash distributions to Unitholders *(note 10)*	(172.5)	(145.1)	(222.7)
Dividends	–	(1.2)	(0.6)
Increase (decrease) in bank credit facilities	(137.0)	29.9	(62.9)
Increase in senior secured notes	174.0	–	–
Increase in deferred charges	(1.5)	–	–
Change in non-cash working capital	(3.6)	1.0	1.0
	$ 99.7	$ 2.9	$ (125.7)
Investing activities			
Expenditures on property, plant & equipment	$ (105.8)	$ (69.1)	$ (84.2)
Acquisition of capital/corporate assets	(210.1)	(59.6)	(84.1)
Proceeds on disposal of property, plant & equipment	2.3	4.5	78.1
(Increase) decrease in cash reserved for future site restoration and reclamation	(6.6)	0.7	(0.3)
Expenditures on future acquisitions	–	(14.1)	–
Change in non-cash working capital	6.4	(10.1)	12.1
	$ (313.8)	$ (147.7)	$ (78.4)
INCREASE (DECREASE) IN CASH FOR THE YEAR	$ 5.6	$ 11.5	$ (13.8)
BANK OVERDRAFT BEGINNING OF THE YEAR	(3.1)	(14.6)	(0.8)
CASH (BANK OVERDRAFT) END OF THE YEAR	$ 2.5	$ (3.1)	$ (14.6)
CASH INTEREST PAID	$ 13.1	$ 10.3	$ 13.2
CASH TAXES PAID	$ 3.9	$ 4.0	$ 0.5

Consolidated Statements of Income

For the years ended December 31 (millions of dollars, except for per Trust Unit amounts)	2003	2002	2001
Revenues			
Sales of crude oil, natural gas and natural gas liquids	**$ 434.6**	$ 320.5	$ 378.2
Crown and other royalties, net of ARTC	**(101.9)**	(56.5)	(73.2)
Other income	**(2.8)**	0.3	1.5
	329.9	264.3	306.5
Expenses			
Operating	**79.4**	60.8	59.0
Cash general and administrative	**14.5**	11.3	10.4
Non-cash general and administrative	**14.4**	6.1	4.2
Interest	**15.1**	10.8	13.8
Cash management fees *(note 11)*	**–**	4.0	6.4
Cash internalization costs	**–**	3.6	–
Non-cash management fees *(note 11)*	**–**	1.4	1.8
Non-cash internalization costs *(note 11)*	**–**	13.1	–
Foreign exchange (gain)/loss	**(11.9)**	–	–
Depletion, depreciation and amortization	**207.3**	182.0	159.3
	318.8	293.1	254.9
Income (loss) before taxes for the year	**11.1**	(28.8)	51.6
Income and capital taxes	**3.8**	2.9	2.4
Future income taxes recovery *(note 12)*	**(83.0)**	(32.3)	(30.3)
	(79.2)	(29.4)	(27.9)
Net income for the year	**$ 90.3**	$ 0.6	$ 79.5
Net income per Trust Unit	**$ 1.96**	$ 0.02	$ 3.12
Diluted net income per Trust Unit	**$ 1.95**	$ 0.02	$ 3.08

Notes to Consolidated Financial Statements

(all amounts are expressed in millions of Canadian dollars unless otherwise indicated)

1. Structure of the Trust

PrimeWest Energy Trust (the Trust) is an open-ended investment trust formed under the laws of Alberta in accordance with a declaration of trust dated August 2, 1996, as Amended. The beneficiaries of the Trust are the holders of Trust Units (the Unitholders).

The principal undertaking of the Trust's operating companies, PrimeWest Energy Inc. and PrimeWest Gas Corp. (collectively referred to as PrimeWest), is to acquire and hold, directly and indirectly, interests in oil and gas properties. One of the Trust's primary assets is a royalty entitling it to receive 99% of the net cash flow generated by the oil and gas interests owned by PrimeWest. The royalty acquired by the Trust effectively transfers substantially all of the economic interest in the properties to the Trust.

The common shares of PrimeWest Energy Inc. are 100% owned by the Trust. PrimeWest Gas Corp. is a wholly owned subsidiary of PrimeWest Energy Inc.

On November 4, 2002, Unitholders voted, by a 92% majority, to internalize management. PrimeWest Management Inc. and its shareholders received a total of $26.3 million in connection with that transaction. Approximately $13.2 million related to the acquisition of the 1% retained royalty and was recorded as an acquisition in property, plant and equipment. The balance was charged to non-cash internalization expense. In addition, retention provisions for senior management totaling $3.5 million were agreed to and $1.5 million was accrued relating to the termination of the management incentive program (see Note 11 to the consolidated financial statements).

2. Accounting Policies

Consolidation

These consolidated financial statements include the accounts of the Trust and its wholly-owned subsidiaries, PrimeWest Energy Inc. and PrimeWest Gas Corp. The Trust, through the royalty, obtains substantially all of the economic benefits of the operations of PrimeWest.

Cash and Short Term Investments

Short term investments, with maturities less than three months at the date of acquisition, are considered to be cash equivalents and are recorded at cost, which approximates market value.

Inventory

Inventory is measured at lower of cost and net realizable value.

Goodwill

Goodwill represents the excess of purchase price over fair value of net assets acquired and liabilities assumed. Goodwill is assessed for impairment at least annually. To assess impairment, the fair value of each reporting unit is determined and compared to the book value of the reporting unit. The amount of the impairment is determined by deducting the fair value of the

reporting unit's assets and liabilities from the fair value of the reporting unit to determine the implied fair value of goodwill and comparing that amount to the book value of the reporting unit's goodwill. Any excess of the book value of goodwill over the implied fair value of goodwill is the impairment amount.

Property, Plant and Equipment

PrimeWest follows the full cost method of accounting. All costs of acquiring oil and gas properties and related development costs are capitalized and accumulated in one cost centre. Maintenance and repairs are charged against earnings. Renewals and enhancements that extend the economic life of the capital asset are capitalized.

Gains and losses are not recognized on disposition of oil and gas properties unless that disposition would alter the rate of depletion by 20% or more.

i) Ceiling test

PrimeWest places a limit on the aggregate cost of capital assets which may be carried forward for depletion against net revenues of future periods (the ceiling test). The ceiling test is a cost recovery test whereby; capitalized costs, less accumulated depletion and site restoration, the lower of cost and market value of unproved land and future income taxes, are limited to an amount equal to estimated undiscounted future net revenues from Proved reserves, less general and administrative expenses, site restoration, future financing costs and applicable income taxes. Costs and prices at the balance sheet date are used. Any costs carried on the balance sheet in excess of the ceiling test limitation are charged to income.

ii) Site restoration and reclamation provision

PrimeWest provides for the cost of future site restoration and reclamation, based on estimates by management, using the unit-of-production method. Actual site restoration costs are charged against the accumulated liability. PrimeWest places cash in reserve to fund actual expenditures as they are incurred.

iii) Depletion, depreciation and amortization

Provision for depletion and depreciation is calculated on the unit-of-production method, based on Proved reserves before royalties. Reserves are estimated by independent petroleum engineers. Reserves are converted to equivalent units on the basis of approximate relative energy content. Depreciation and amortization of head office furniture and equipment is provided for at rates ranging from 10% to 30%.

Joint Venture Accounting

PrimeWest conducts substantially all of its oil and gas production activities through joint ventures, and the accounts reflect only PrimeWest's proportionate interest in such activities.

Long-Term Incentive Plan

Liabilities under the Trust's Long-term Incentive Plan are estimated at each balance sheet date, based on the amount of Unit Appreciation Rights that are in the money using the unit price as at that date. Expenses are recorded through non-cash general and administrative costs, with an offsetting amount in long-term incentive plan equity. As Trust Units are issued under the plan, the exercise value is recorded in net capital contributions.

Income Taxes

The Trust is considered an inter-vivos trust for income tax purposes. As such, the Trust is subject to tax on any taxable income that is not allocated to the Unitholders. Periodically, current taxes may be payable by PrimeWest, depending upon the timing of income tax deductions. Should these taxes prove to be unrecoverable, they will be deducted from royalty income in accordance with the royalty agreement.

Future income taxes are recorded for PrimeWest using the liability method of accounting. Future income taxes are recorded to the extent that the carrying value of PrimeWest's capital assets exceeds the available tax pools.

Financial Instruments

PrimeWest uses financial instruments to manage its exposure to fluctuations in commodity prices and interest rates. PrimeWest does not use financial instruments for speculative trading purposes and, accordingly, they are accounted for as hedges. Gains and losses on hedging activity are reflected in revenue, or in the case of interest rate hedges, in interest expense, at the time of sale of the related hedged production, or when the monthly exchange contracts expire.

Measurement Uncertainty

Certain items recognized in the financial statements are subject to measurement uncertainty. The recognized amounts of such items are based on PrimeWest's best information and judgment. Such amounts are not expected to change materially in the near term. They include the amounts recorded for depletion, depreciation and future site restoration costs which depend on estimates of oil and gas reserves or the economic lives and future cash flows from related assets.

3. Corporate Acquisitions

a) On January 23, 2003, PrimeWest Gas Inc. completed the acquisition of two private Canadian oil and gas companies. Subsequent to the transaction, PrimeWest Gas Inc. was wound up into PrimeWest Energy Inc. The acquired companies were amalgamated with PrimeWest Gas Corp. The acquisition was accounted for using the purchase method of accounting with net assets acquired and consideration paid as follows:

Net Assets Acquired at Assigned Values		Consideration Paid	
Petroleum and natural gas assets	$ 220.9		
Goodwill	56.1		
Working capital, including cash of $3.9	0.7		
Site restoration provision	(5.4)	Cash	$ 212.7
Future income taxes	(53.2)	Costs associated with acquisition	6.4
	$ 219.1		$ 219.1

b) On March 29, 2001, PrimeWest Oil & Gas Corp. (Oil & Gas) completed the acquisition of all of the issued and outstanding shares of Cypress Energy Inc. (Cypress) pursuant to a takeover bid. In aggregate, PrimeWest issued 50.2 million Trust Units and PrimeWest issued 5.2 million Exchangeable shares of Oil & Gas and paid $59.2 million in exchange for the shares of Cypress.

Subsequent to the transaction, Cypress and Oil & Gas were amalgamated. On January 1, 2002, PrimeWest Oil and Gas Corp. and PrimeWest Energy Inc. were amalgamated. The acquisition was accounted for using the purchase method of accounting with net assets acquired and consideration paid as follows:

Net Assets Acquired at Assigned Values		Consideration Paid	
Petroleum and natural gas assets	$1,201.5		
Working capital deficit assumed	(19.2)	Cash	$ 59.2
Long-term debt assumed	(179.0)	Trust Units issued	489.8
Site restoration provision	(4.3)	Exchangeable shares issued	50.3
Future income taxes	(376.3)	Costs associated with acquisition	23.4
	$ 622.7		$ 622.7

4. Property, Plant and Equipment

	2003		
	Cost	Accumulated Depletion Depreciation and Amortization	Net Book Value
Property acquisition oil and gas rights	**$ 1,917.4**	**$ (607.0)**	**$ 1,310.4**
Drilling and completion	**208.0**	**(52.1)**	**155.9**
Production facilities and equipment	**91.0**	**(23.1)**	**67.9**
Head office furniture and equipment	**8.0**	**(4.6)**	**3.4**
	$ 2,224.4	**$ (686.8)**	**$ 1,537.6**

	2002		
	Cost	Accumulated Depletion Depreciation and Amortization	Net Book Value
Property acquisition oil and gas rights	$ 1,682.6	$ (430.6)	$ 1,252.0
Drilling and completion	139.9	(34.7)	105.2
Production facilities and equipment	60.5	(15.4)	45.1
Head office furniture and equipment	5.2	(3.0)	2.2
	$ 1,888.2	$ (483.7)	$ 1,404.5

	2001		
	Cost	Accumulated Depletion Depreciation and Amortization	Net Book Value
Property acquisition oil and gas rights	$ 1,608.4	$ (268.1)	$ 1,340.3
Drilling and completion	103.6	(24.1)	79.5
Production facilities and equipment	38.2	(11.5)	26.7
Head office furniture and equipment	4.2	(2.0)	2.2
	$ 1,754.4	$ (305.7)	$ 1,448.7

Unproved land costs of $36.0 million (2002 – $44.2 million; 2001 – $55.7 million) are excluded from costs subject to depletion and depreciation.

PrimeWest capitalized $2.5 million of general and administrative costs in 2003 (2002 – $2.5 million; 2001 – $2.2 million).

In accordance with stated accounting policies, PrimeWest has performed a ceiling test using commodity prices as at the measurement date of December 31, 2003. Using December 31, 2003 commodity prices of AECO $6.09/mcf for natural gas and WTI US$32.52/bbl for crude oil, results in a ceiling test surplus.

A ceiling test surplus existed as at December 31, 2002.

At December 31, 2001, PrimeWest performed its ceiling test using commodity prices as at that measurement date of AECO $3.67/mcf for natural gas, and WTI US$19.84/bbl for crude oil. The ceiling test resulted in a deficiency of $150 million. PrimeWest did not record a write-down at that time as the write-down occurred within the first two years of the acquisition of Cypress Energy Inc.

5. Other Assets

	2003	2002	2001
Deposit on acquisition	$ –	$ 10.9	$ –
Expenditures incurred on acquisition	–	3.3	–
Other assets	0.2	0.2	–
	$ 0.2	$ 14.4	$ –

6. Long-Term Debt

	2003	2002	2001
Revolving credit facility	$ 88.0	$ 225.0	$ 195.0
Senior secured notes	162.1	–	–
	$ 250.1	$ 225.0	$ 195.0

PrimeWest and the Trust (as co-borrowers) have combined revolving credit facilities in the amount of $213 million (2002 – $335 million; 2001 – $350 million), with a borrowing base at December 31, 2003 of $390 million (2002 – $335 million; 2001 – $350 million). The facilities consist of a revolving term loan of $188 million and an operating facility of $25 million. In addition to amounts outstanding under the facilities as indicated in the table above, PrimeWest has outstanding letters of credit in the amount of $5.1 million (2002 – $3.8 million; 2001 – $2.8 million).

Advances under the facility are made in the form of Banker's Acceptances (BA), prime rate loans or letters of credit. In the case of BA, interest is a function of the BA rate plus a stamping fee based on the Trust's current ratio of debt to cash flow. In the case of prime rate loans, interest is charged at the bank's prime rate. While any amounts are outstanding under the bridge facility, the interest rates and stamping fees increase by 50 basis points. For 2003, the effective interest rate was 4.7% (2002 – 4.6%; 2001 – 5.6%).

The credit facility revolves until June 30, 2004, by which time the lenders will have conducted their annual borrowing base review. The lender also has the right to redetermine the borrowing base at one other time during the year. During the revolving phase, the facility has no specific terms of repayment. At the end of the revolving period, the lender has the right to extend the revolving period for a further 364-day period or to convert the facility to a term facility. If the lender converts to a non-revolving facility, 60% of the aggregate principal amount of the loan shall be repayable on the date which is 366 days after such conversion date and the remaining 40% of the aggregate principal amount outstanding shall be repayable on the date which is 365 days after the initial term repayment date.

On May 7, 2003, PrimeWest replaced a portion of its bank debt with Senior Secured Notes (the "Notes") in the amount of US$125 million. They have a final maturity of May 7, 2010, and bear interest at 4.19% per annum, with interest paid semi-annually on November 7 and May 7 of each year. The Note Purchase Agreement requires PrimeWest to make four annual principal repayments of US$31,250,000 commencing May 7, 2007.

Collateral for the secured note and credit facility is a floating charge debenture covering all existing and after acquired property in the principal amount of US$1 billion. The secured parties for the revolving credit facilities and senior secured notes have agreed to share the security interests on a *pari passu* basis.

The costs incurred in connection with the Notes, in the amount of $1.5 million, are classified as deferred charges on the balance sheet and are being amortized over the term of the Notes.

The Senior Secured Notes are the legal obligation of PrimeWest Energy Inc. and are guaranteed by PrimeWest Energy Trust.

7. Cash Reserve for Site Restoration and Reclamation

Commencing in 1998, funding for the reserve was provided for by reducing distributions otherwise payable based on an amount/BOE produced ($0.15/BOE produced for 1998 and 1999, $0.24/BOE produced in 2000, $0.32/BOE produced in 2001, $0.37/BOE produced in 2002 and $0.50/BOE produced in 2003). The cash amount contributed, including interest earned, was $6.2 million in 2003 (2002 – $4.1 million; 2001 – $4.2 million). During 2003, an additional contribution of $4.2 million was made to fund reclamation expenditures associated with properties acquired in 2002. Actual costs of site restoration and abandonment totaling $2.2 million were paid out of this cash reserve for the year ended December 31, 2003 (2002 – $3.9 million; 2001 – $3.8 million).

8. Unitholders' Equity

PrimeWest Energy Trust

The authorized capital of the Trust consists of an unlimited number of Trust Units.

Trust Units	Number of Units	Amounts ($)
Balance, December 31, 2000	50,982,093	$ 428.0
Issued for cash	19,790,000	165.2
Issue expenses	–	(9.0)
Issued to acquire Cypress Energy Inc.	50,234,771	489.8
Issued for payment of management fees	199,841	1.7
Issued on exchange of Exchangeable shares	2,415,363	20.3
Issued pursuant to Distribution Reinvestment Plan	1,623,171	10.8
Issued pursuant to Long-Term Incentive Plan	577,840	5.2
Issued pursuant to Optional Trust Unit Purchase Plan	142,528	3.3
Balance, December 31, 2001	125,965,607	$ 1,115.3
Restated giving effect for 4 to 1 Trust Unit consolidation on August 16, 2002	31,491,402	–
Issued for cash	4,200,000	110.0
Issue expenses	–	(5.6)
Issued for payment of management fees	66,853	1.8
Issued on exchange of Exchangeable shares	106,934	2.7
Issued pursuant to Distribution Reinvestment Plan	476,106	10.1
Issued pursuant to Long-Term Incentive Plan	153,749	4.0
Issue of units due to odd lot program	111	–
Issue of fractional units due to 4 to 1 consolidation	6,264	–
Issued pursuant to Optional Trust Unit Purchase Plan	503,103	14.0
Balance, December 31, 2002	37,004,522	$ 1,252.3
Issued for cash	9,100,000	234.8
Issue expenses	–	(12.2)
Issued on exchange of Exchangeable shares	964,897	21.2
Issued pursuant to Distribution Reinvestment Plan	600,598	14.8
Issued pursuant to Long-Term Incentive Plan	360,608	9.4
Issue of units due to odd lot program	38	–
Issue of fractional units due to 4 to 1 consolidation	11	–
Issued pursuant to Optional Trust Unit Purchase Plan	721,209	17.6
Balance, December 31, 2003	**48,751,883**	**$ 1,537.9**

The number of units was restated giving effect of four for one Trust Unit consolidation effective August 16, 2002.

The weighted average number of Trust Units and Exchangeable shares outstanding in 2003 was 46,015,519 (2002 – 34,135,576; 2001 – 25,633,271). For purposes of calculating diluted net income per Trust Unit, 345,278 Trust Units (2002 – 341,315; 2001 – 311,789) issuable pursuant to the long-term incentive plan were added to the weighted average number. The per unit cash distribution amounts paid or declared reflects distributions paid or declared to Trust Units outstanding on the record dates.

PrimeWest Exchangeable Class A Shares

In connection with the Cypress transaction (see Note 3b), PrimeWest Oil & Gas Corp. (now amalgamated with PrimeWest Energy Inc.) amended its articles to create an unlimited number of Exchangeable shares. The Exchangeable shares are exchangeable into PrimeWest Trust Units at any time up to March 29, 2010, based on an exchange ratio that adjusts each time the Trust makes distribution to its Unitholders. The exchange ratio, which was 1:1 on the date that the transaction closed, is based on the total monthly distribution, divided by the closing unit price on the distribution payment date. The exchange ratio on December 31, 2003 was 0.44302:1 (2002 – 0.37454:1; 2001 – 0.3126:1, restated effecting 4 to 1 Trust Unit consolidation).

Exchangeable Shares	# of Shares	Amounts ($)
Balance, December 31, 2001	3,316,742	$ 32.3
Issued for internalization	1,363,714	13.1
Conversion of Class B shares	710,795	4.3
Exchanged for Trust Units	(211,973)	(2.0)
Balance, December 31, 2002	5,179,278	47.7
Issued for management incentive program	161,717	1.5
Exchanged for Trust Units	(2,299,872)	(21.2)
Balance, December 31, 2003	**3,041,123**	**$ 28.0**

PrimeWest Exchangeable Class B Shares

In connection with a transaction in 2000, PrimeWest Resources Ltd. (now amalgamated with PrimeWest Energy Inc.) amended its articles to create an unlimited number of Exchangeable shares. At special meetings held in May and June of 2002, holders of Class B Exchangeable shares and Class A Exchangeable shares voted to approve a special resolution amending the articles of the Corporation to convert all Class B Exchangeable shares to Class A Exchangeable shares. As at June 14, 2002, 649,561 Class B Exchangeable shares were converted to Class A Exchangeable shares using an exchange ratio of 1.09427:1.

Exchangeable Shares	# of Shares	Amounts ($)
Balance, December 31, 2001	751,532	$ 5.0
Exchanged for Trust Units	(101,971)	(0.7)
Converted to Class A Exchangeable shares	(649,561)	(4.3)
Balance, December 31, 2002	–	$ –

Trust Units and Exchangeable Shares Issued & Outstanding[1]

	2003	2002	2001
Trust Units issued & outstanding	**48,751,883**	37,004,522	31,491,402
Exchangeable shares			
Class A Shares (2003 – 3,041,123 shares exchangeable at 0.44302; 2002 – 5,179,278 shares exchangeable at 0.37454; 2001 – 3,316,742 shares exchangeable at 0.3126)	**1,347,277**	1,939,864	1,036,648
Class B Shares (2001 – 751,532 shares exchangeable at 0.34201)	–	–	257,035
Total units and Exchangeable shares issued & outstanding	**50,099,160**	38,944,386	32,785,085
Unit Appreciation Rights	**345,278**	341,315	311,788
Total units and Exchangeable shares issued & outstanding – diluted	**50,444,438**	39,285,701	33,096,873

[1] Restated Trust Units to give effect to 4 for 1 unit consolidation effective August 16, 2002.

9. Trust Unit Incentive Plan

Under the terms of the Trust Unit Incentive Plan, a maximum of 1,800,000 Trust Units are reserved for issuance pursuant to the exercise of Unit Appreciation Rights (UARs) granted to employees of PrimeWest. Payouts under the plan are based on total Unitholder return, calculated using both the change in the Trust Unit price as well as cumulative distributions paid. The plan requires that a hurdle return of 5% per annum be achieved before payouts accrue. UARs have a term of up to six years and vest equally over a three-year period, except for the members of the Board, whose UARs vest immediately. The Board of Directors has the option of settling payouts under the plan in PrimeWest Trust Units or in cash. To date, all payouts under the plan have been in the form of Trust Units.

As at December 31, 2003 Year of Grant	UARs Issued & Outstanding	UARs Vested	Current Return per "In the Money" UARs	Total Equity	Trust Unit Dilution
1998	10,391	10,391	$ 49.98	$ 0.5	18,844
1999	55,160	55,160	34.92	1.9	69,892
2000	120,137	119,387	16.40	2.0	71,007
2001	383,424	265,645	7.81	3.0	74,891
2002	961,405	447,562	6.09	4.7	86,694
2003	1,085,031	141,896	4.75	2.5	23,950
Total	2,615,548	1,040,041		$ 14.6	345,278

As at December 31, 2002 Year of Grant	UARs Issued & Outstanding	UARs Vested	Current Return per "In the Money" UARs	Total Equity	Trust Unit Dilution
1997	52,927	52,927	$ 22.98	$ 1.2	47,883
1998	105,798	105,798	33.99	3.6	141,563
1999	115,215	114,667	22.38	2.6	101,076
2000	187,984	125,661	8.22	1.5	37,831
2001	515,634	185,780	2.12	0.6	12,861
2002	1,120,142	82,097	1.97	0.5	101
Total	2,097,700	666,930		$ 10.0	341,315

As at December 31, 2001 Year of Grant	UARs Issued & Outstanding	UARs Vested	Current Return per "In the Money" UARs	Total Equity	Trust Unit Dilution
1996	131,719	131,719	$ 15.84	$ 2.1	82,010
1997	79,839	79,839	13.76	1.1	43,165
1998	127,956	127,957	24.80	3.2	124,654
1999	148,416	89,566	14.76	1.3	52,025
2000	240,914	86,951	2.92	0.2	9,935
2001	629,343	25,211	–	–	–
Total	1,358,187	541,243		$ 7.9	311,789

Cumulative to December 31, 2003, 1,030,850 UARs have been exercised (cumulative to December 31, 2002 – 640,503; cumulative to December 31, 2001 – 399,199), resulting in the issuance of 719,374 Trust Units from treasury (cumulative to December 31, 2002 – 358,766; cumulative to December 31, 2001 – 205,017).

10. Cash Distributions

	2003	2002	2001
Net income for the year	$ 90.3	$ 0.6	$ 79.5
Add back (deduct) amounts to reconcile to distribution:			
Depletion, depreciation and amortization	207.3	182.0	159.3
Cash (retained) / paid from cash available for distribution	(15.6)	(7.3)	25.8
Contribution to reclamation fund	(8.7)	(4.1)	(3.5)
Non-cash general and administrative	14.4	6.1	4.2
Non-cash foreign exchange	(12.1)	–	–
Internalization costs paid in Trust Units	–	13.1	–
Management fees paid in Trust Units	–	1.4	1.8
Future income taxes recovery	(83.0)	(32.3)	(30.3)
	$ 192.6	$ 159.5	$ 236.8
Cash distributions to Trust Unitholders	$ 192.6	$ 158.0	$ 234.4
Cash distributions per Trust Unit	$ 4.32	$ 4.80	$ 9.24

11. Related – Party Transactions

On September 26, 2002, the Trust announced the planned elimination, effective October 1, 2002, of its external management structure and all related management, acquisition and disposition fees, as well as the acquisition of the right to mandatory quarterly dividends commonly referred to as the "1% retained royalty". The transaction was approved by the Unitholders and the holders of Exchangeable shares on November 4, 2002 and closed November 6, 2002. The transaction resulted in the elimination of the 2.5% management fee on net production revenue, quarterly incentive payments payable in the form of Trust Units, the 1.5% acquisition fee and the 1.25% disposition fee, which resulted in payments to PrimeWest Management Inc. in 2002 totaling $5.8 million (2001 – $21.3 million). In addition, the amount of the 1% retained royalty paid in 2002 was $1.3 million (2001 – $3.4 million).

As at December 31, 2002, the Trust and PrimeWest owed $nil (2001 – $10.1 million) to PrimeWest Management Inc. for unpaid management and other fees and reimbursement of general and administrative costs.

The internalization transaction was achieved through the purchase by PrimeWest of all of the issued and outstanding shares of PrimeWest Management Inc. for a total consideration of approximately $26.3 million comprised of a cash payment of $13.2 million and the issuance of Exchangeable shares exchangeable, based on an agreed exchange ratio, for approximately 491,000 Trust Units and valued at approximately $13.1 million based on the closing price of the Trust Units on the TSX on September 26, 2002. The $13.2 million that related to the acquisition of the 1% retained royalty was capitalized; an additional $9.5 million was capitalized with an offset to future tax liability as a result of the property, plant and equipment having no tax basis. In addition, PrimeWest agreed to issue Exchangeable shares valued at $1.5 million to certain senior managers to terminate a

management incentive program of PrimeWest Management Inc. and to create a special employee retention plan for those senior managers which provides for long term incentive bonuses in the form of Exchangeable shares valued, in the aggregate, at $3.5 million. Exchangeable shares will be issued pursuant to the retention plan on each of the second, third, fourth and fifth anniversaries of the completion of the internalization transaction. As at December 31, 2003, $0.5 million has been accrued in non-cash general and administrative expenses related to the special employee retention plan.

12. Income Taxes

PrimeWest and its subsidiaries had no taxable income for 2003, 2002, and 2001, as tax pool deductions and the royalty payable were sufficient to reduce taxable income in these entities to nil.

The future tax provision results from temporary differences between the financial statement carrying amounts of assets and liabilities and their respective tax bases.

	2003	2002	2001
Loss carry forwards	**$ –**	$ (5.0)	$ (10.6)
Capital assets	**318.9**	350.0	378.0
Foreign exchange gain on long term debt	**2.1**	–	–
Site restoration provision	**(6.0)**	(1.9)	(2.3)
Long-term incentive liability	**(4.9)**	(3.2)	(2.5)
	$ 310.1	$ 339.9	$ 362.6

The provisions for income taxes varies from the amounts that would be computed by applying the combined Canadian federal and provincial income tax rates for the following reasons:

	2003	2002	2001
Net income (loss) before taxes	**$ 11.1**	$ (28.8)	$ 51.6
Computed income tax expense (recovery) at the Canadian statutory rate of 40.62% (2002 – 42.12%; 2001 – 43.12%)	**4.5**	(12.1)	22.3
Increase (decrease) resulting from:			
Non-deductible Crown royalties and other payments, net of ARTC	**0.3**	5.7	0.2
Federal resource allowance	**(16.2)**	(3.5)	(9.7)
Change in income tax rate	**(43.1)**	(4.2)	–
Amounts included in Trust income and other	**(28.5)**	(18.2)	(43.1)
Future income taxes	**$ (83.0)**	$ (32.3)	$ (30.3)

13. Financial Instruments

a) Commodity Price Risk Management

PrimeWest generally sells its oil and gas under short term market-based contracts. Derivative financial instruments, options and swaps may be used to hedge the impact of oil and gas price fluctuations. A summary of these contracts in place at December 31, 2003 follows:

Crude Oil

Period	Volume (bbls/d)	Type	WTI Price (US$/bbl)
Jan – Jan 2004	500	Swap	$ 33.30
Jan – Mar 2004	1,000	Swap	27.29
Jan – Mar 2004	500	Swap	28.87
Jan – Mar 2004	500	Swap	30.21
Jan – Mar 2004	500	Swap	31.60
Jan – Mar 2004	500	Costless Collar	22.00/26.70
Jan – Mar 2004	500	Costless Collar	23.00/33.30
Jan – Mar 2004	500	Costless Collar	24.00/31.20
Jan – Mar 2004	500	Costless Collar	25.00/28.16
Apr – Jun 2004	1,000	Swap	27.13
Apr – Jun 2004	500	Swap	28.64
Apr – Jun 2004	500	Swap	30.06
Apr – Jun 2004	500	Costless Collar	22.00/26.12
Apr – Jun 2004	500	Costless Collar	24.00/30.50
Apr – Jun 2004	500	Costless Collar	25.00/28.07
Apr – Jun 2004	500	Costless Collar	26.00/32.07
Jul – Sep 2004	500	Swap	26.07
Jul – Sep 2004	500	Swap	27.04
Jul – Sep 2004	500	Swap	28.51
Jul – Sep 2004	500	Costless Collar	24.00/30.75
Jul – Sep 2004	500	Costless Collar	25.00/28.30
Jul – Sep 2004	500	Costless Collar	26.00/32.05
Oct – Dec 2004	500	Swap	26.00
Oct – Dec 2004	500	Swap	27.03
Oct – Dec 2004	500	Swap	28.53
Oct – Dec 2004	500	Costless Collar	24.00/30.00
Oct – Dec 2004	500	Costless Collar	25.00/28.30
Jan 2005 – Mar 2005	500	Swap	27.25
Apr 2005 – Jun 2005	500	Swap	27.07
Jul 2005 – Sep 2005	500	Swap	27.05

Natural Gas (AECO)

Period	Volume (mmcf/day)	Type	AECO Price (Cdn$/mcf)
Jan 2004 – Mar 2004	4.7	Swap	$ 6.19
Jan 2004 – Mar 2004	4.7	3 Way	4.22/5.28/8.23
Jan 2004 – Mar 2004	4.7	3 Way	4.48/5.54/6.52
Jan 2004 – Mar 2004	4.7	Costless Collar	6.33/7.91
Jan 2004 – Mar 2004	4.7	Costless Collar	6.33/11.87
Jan 2004 – Mar 2004	4.7	Costless Collar	5.80/8.23
Jan 2004 – Mar 2004	4.7	Costless Collar	5.80/8.33
Jan 2004 – Mar 2004	4.7	Costless Collar	6.33/8.58
Jan 2004 – Mar 2004	4.7	Costless Collar	4.75/7.91
Jan 2004 – Oct 2004	9.5	3 Way	3.17/4.22/6.09
Jan 2004 – Dec 2004	1.0	Swap	6.02
Apr 2004 – Oct 2004	4.7	Swap	5.45
Apr 2004 – Oct 2004	4.7	Swap	6.02
Apr 2004 – Oct 2004	4.7	Swap	6.06
Apr 2004 – Oct 2004	4.7	Costless Collar	5.01/6.06
Apr 2004 – Oct 2004	4.7	Costless Collar	5.28/7.39

A 3 way option is like a traditional collar, except that PrimeWest has resold the put at a lower price. Utilizing the first 3 Way natural gas contract above as an example, PrimeWest has sold a call at $8.23, purchased a put at $5.28, and resold the put at $4.22. Should the market price drop below $5.28 PrimeWest will receive $5.28 until the price is less than $4.22, at which time PrimeWest would then receive market price plus $1.06. However, should market prices rise above $8.23, PrimeWest would receive a maximum of $8.23. Should the market price remain between $5.28 and $8.23, PrimeWest would receive the market price.

Natural Gas (Basis differential US$/MCF)

Period	Volume (mmcf/day)	Type	Basis Price (US$/mcf)
Jan – Mar 2004	10.0	Basis Swap	$ 0.63
Apr – Oct 2004	5.0	Basis Swap	$ 0.71

The AECO basis is the difference between the NYMEX gas price in US$ per mcf and the AECO price in US$ per mcf. Using the first basis swap above as an example, PrimeWest has fixed this price difference between the two markets at US$0.63 per mcf from January 2004 through March 2004. If the NYMEX price for the period turned out to be US$4.00 per mcf, PrimeWest would receive an AECO equivalent price of US$3.37 per mcf.

In 2003, the financial impact of contracts settling in the year was a decrease in sales revenues of $30.5 million (2002 – $28.1 million increase in sales revenues; 2001 – $39.5 million increase in sales revenues).

The mark-to-market value of the hedges in place as at December 31, 2003 is a $6.0 million loss of which $2.1 million is attributable to natural gas and $3.9 million is attributable to crude oil.

Electrical Power

Period	Power Amount (MW)	Type	Price ($/MW-hr)
Q1 2004	5.0	Fixed Price Swap	$ 58.50
Q2 2004	7.5	Fixed Price Swap	40.25
Q3 2004	5.0	Fixed Price Swap	46.50
Q4 2004	5.0	Fixed Price Swap	44.00
Calendar 2004	5.0	Fixed Price Swap	45.65

The mark-to-market value of the electrical power swaps at December 31, 2003 is a $0.6 million gain.

b) Interest Rate Risk Management

PrimeWest has the following interest rate swaps outstanding at December 31, 2003.

Interest Rate Risk Management

Term	Notional Amount ($ millions)	Fixed BA Rate (%)
May 24/98 – May 25/04	$ 25	6.48
Nov 26/01 – May 26/04	$ 25	3.85

The mark-to-market value of the interest rate swaps is a $0.6 million loss at December 31, 2003.

The effect of the interest rates swaps was to increase interest paid in 2003 by $0.9 million (2002 – $1.5 million; 2001 – $0.4 million).

c) Fair Value of Financial Instruments

Financial instruments include cash, accounts receivable, accounts payable and accrued liabilities, accrued distributions to Unitholders, long-term debt and financial hedges. As at December 31, 2003, 2002, and 2001, the fair market value of the financial instruments, other than long-term debt and financial hedges, approximate their carrying value, due to the short term maturity of these instruments. The fair value of long-term debt approximates its carrying value in all material respects, because the cost of borrowing approximates the market rate for similar borrowings.

14. Commitments and Contingencies

a) PrimeWest has lease commitments relating to office buildings. The estimated annual minimum operating lease rental payments for the buildings, after deducting sublease income will be $1.2 million in 2004, $1.1 million in 2005, $1.1 million in 2006 and $2.4 million in 2007 – 2009, the remaining term of the leases.

b) As part of PrimeWest's internalization transaction (see Note 11), PrimeWest agreed to pay $3.5 million in Exchangeable shares as a special employee retention plan. One quarter of the Exchangeable shares will be issuable to the senior managers of PrimeWest on each of the second, third, fourth and fifth anniversary of transaction closing, November 6, 2002. As at December 31, 2003 $0.5 million has been accrued in non-cash general and administrative expenses.

c) PrimeWest is engaged in a number of matters of litigation, none of which could reasonably be expected to result in any material adverse consequence.

d) PrimeWest has a pipeline transportation commitment that runs to October 31, 2007 and has a minimum annual payment requirement of US$2.1 million.

15. Subsequent Event

On January 27th, 2004, PrimeWest announced that it had agreed to make an offer to acquire all of the shares of Seventh Energy. Seventh Energy's Board and executive unanimously approved the transaction and have agreed to tender their approximately 24% ownership interest. The acquisition cost is expected to be $42.6 million comprised of the assumption of $8.3 million of debt and working capital and a cash payment of $34.3 million. To protect the transaction economics, PrimeWest hedged approximately 70% of Seventh Energy's gas production at a price of $6.18/mcf for one year. PrimeWest's existing credit line will be used to fund the cash portion of the acquisition. The offer is currently set to expire on March 15, 2004.

16. Prior Years' Comparative Numbers

Certain prior years' comparative numbers have been restated to conform with the current year's presentation.

17. Differences Between Canadian And United States Generally Accepted Accounting Principles

PrimeWest's financial statements are prepared in accordance with accounting principles generally accepted (GAAP) in Canada which, in some respects differ from those generally accepted in the United States (U.S.). The following are those policies that result in significant measurement differences.

1. Property, Plant And Equipment

PrimeWest follows the full cost accounting guideline as established by the Canadian Institute of Chartered Accountants (CICA). Under this guideline, the net carrying value of the Trust's oil and gas properties is limited to an estimated recoverable amount calculated as aggregate undiscounted future net revenues, after deducting future general and administrative costs, financing costs, and income taxes. In accordance with the full cost method of accounting under U.S. GAAP, the net carrying value is limited to a standardized measure of discounted future cash flows, before financing and general administrative costs. Where the amount of a ceiling test write-down under Canadian GAAP differs from the amount of a write down under U.S. GAAP, the charge for depreciation and depletion under U.S. and Canadian GAAP will differ in subsequent years.

2. Derivative Financial Instruments

Effective January 1, 2001, PrimeWest adopted Financial Accounting Standard (FAS) 133, Accounting for Derivative Instruments and Hedging Activities, as amended by FAS 138, which establishes accounting and reporting standards for derivative instruments, including certain derivative instruments embedded in other contracts and for hedging activities. All derivatives, whether designated in hedging relationships or not, and excluding normal purchase and sales are required to be recorded on the balance sheet at fair value. If the derivative is designated as a fair value hedge, the changes in the fair value of the derivative and of the hedged item attributable to the hedged risk are recognized in earnings. If the derivative is designated as a cash flow hedge, the effective portions of the changes in fair value of the derivative are recorded in other comprehensive income (OCI) and are recognized in the income statement when the hedged item is realized. Ineffective portions of changes in the fair value and the cash flow hedges are recognized in earnings, immediately.

The adoption of FAS 133 resulted in OCI of $1.0 million. Assets increased by $1.0 million as a result of recording derivative instruments on the consolidated balance sheet at fair value.

Implementation of this accounting standard did not affect the Trust's cash flow or liquidity.

3. Asset Retirement Obligation

Effective January 1, 2003, the Trust adopted FAS 143 Accounting for Asset Retirement Obligations. The new standard requires the recognition of the liability associated with the future site reclamation costs of the long-lived assets. The liability for future retirement obligations is to be recorded in the financial statements at the time the liability is incurred.

The asset retirement obligation is initially recorded at the estimated fair value as a long-term liability with a corresponding increase to property, plant and equipment. The depreciation of property, plant and equipment is allocated to expense on the unit-of-production basis.

The adoption of FAS 143 allows for the cumulative effect of the change in accounting policy to be booked as a transitional adjustment to net income with no restatement of prior period comparatives. At January 1, 2003 this resulted in an increase to the asset retirement obligation of $15.3 million, an increase to PP&E of $8.4 million, a $0.4 million decrease to net income after tax, a decrease in the site restoration provision of $6.2 million and a decrease to future tax liability of $0.3 million.

Implementation of this accounting standard did not affect the Trust's cash flow or liquidity.

4. Accounting for Certain Financial Instruments with Characteristics of Both Liabilities and Equity

In May 2003, FAS 150 was issued to establish standards for the measurement and classification of certain financial instruments with characteristics of both liabilities and equity. FAS 150 is effective for financial instruments entered into or modified after May 31, 2003. The standard has been adopted by the Trust with no impact.

Recent U.S. Accounting Pronouncements Issued But Not Implemented

Variable Interest Entities

In December 2003, the Financial Accounting Standards Board (FASB) in the United States issued Interpretation Number 46R "Consolidation of Variable Interest Entities, an interpretation of Accounting Research Bulletin No. 51". The standard mandates that variable interest entities be consolidated by their primary beneficiary. The standard is effective the first reporting period ending after March 15, 2004 for all entities with the exception of special purpose entities as defined in prior accounting guidance. The standard is effective for the first period ending after December 15, 2003 for previously defined special purpose entities. In Canada, the Accounting Standards Board (AcSB) has suspended the effective dates for Accounting Guideline AcG15, "Consolidation of Variable Interest Entities" in order to amend the guideline to harmonize with the corresponding U.S. guidance. The AcSB plans to issue an exposure draft in the immediate future with an effective period beginning on or after November 1, 2004. At December 31, 2003, the Trust did not have any variable interests in special purpose entities.

The following tables set out the significant differences in the consolidated financial statements using U.S. GAAP.

a) Consolidated Net Income

(millions of Canadian dollars, except per Trust Unit amounts)	2003	2002	2001
Net income as reported	**$ 90.3**	$ 0.6	$ 79.5
Adjustments			
Depletion and depreciation	**35.4**	67.3	(539.3)
FAS 133 adjustment	**6.1**	(55.8)	43.3
Accretion of asset retirement obligation	**(1.2)**	–	–
Future income tax (expense)/recovery	**(42.3)**	(1.4)	165.2
Adjusted net income/(loss) before change in accounting policy	**88.3**	10.7	(251.3)
Cumulative effect of change in accounting policy, net of tax of $0.3 million	**(0.4)**	–	–
Adjusted net income/(loss)	**87.9**	10.7	(251.3)
Other comprehensive income			
Cumulative effect type adjustment – fair value of cash flow hedging instruments	**–**	–	(1.0)
Change during the year	**–**	–	1.0
Accumulated other comprehensive income	**–**	–	–
Adjusted net and comprehensive income/(loss)	**$ 87.9**	$ 10.7	$ (251.3)
Net income/(loss) per Trust Unit			
U.S. GAAP – basic	**$ 1.91**	$ 0.31	$ (9.80)
– diluted	**$ 1.90**	$ 0.31	$ (9.80)
Cumulative effect of change in accounting policy per Trust Unit			
U.S. GAAP – basic	**$ 0.01**	–	–
– diluted	**$ 0.01**	–	–

b) Pro Forma Consolidated Net Income

U.S. GAAP requires the cumulative impact of a change in accounting policy to be presented in the current year's consolidated statement of income with no restatement of the comparative prior periods. The following table illustrates the pro forma impact on the Trust's net income under U.S. GAAP had the prior period been restated.

(millions of Canadian dollars, except per Trust Unit amounts)	2002	2001
Net income/(loss)		
As reported	$ 10.7	$ (251.3)
As restated	$ 11.5	$ (250.0)
Net income/(loss) per Trust Unit (Basic)		
As reported	$ 0.31	$ (9.80)
As restated	$ 0.34	$ (9.77)
Net income/(loss) per Trust Unit (Diluted)		
As reported	$ 0.31	$ (9.80)
As restated	$ 0.34	$ (9.77)
Asset retirement obligation	$ 15.30	$ 11.80

c) Consolidated Unitholders' Equity

(millions of Canadian dollars)	2003	2002
Unitholders' equity as reported	**$ 1,019.6**	$ 847.1
Adjustments		
Depletion and depreciation	**(493.6)**	(530.9)
FAS 133 adjustment	**(5.4)**	(11.5)
Accretion of asset retirement obligation	**(3.7)**	–
Future income tax recovery	**127.0**	169.1
	$ 643.9	$ 473.8

d) Consolidated Balance Sheets

(millions of Canadian dollars)	2003		2002	
	Cdn. GAAP	**U.S. GAAP**	Cdn. GAAP	U.S. GAAP
Property, plant and equipment (net)	**$ 1,537.6**	**$ 1,042.1**	$ 1,404.5	$ 873.6
Other liabilities	**–**	**5.4**	–	11.5
Future income tax liability	**310.1**	**183.0**	339.9	170.8
Site restoration provision	**17.8**	**–**	6.2	6.2
Asset retirement obligation	**–**	**19.7**	–	–
Accumulated income/(deficit)	**213.5**	**(162.2)**	123.2	(250.1)

e) Consolidated Cash Flows

The consolidated statements of cash flows prepared in accordance with Canadian GAAP conform in all material respects with U.S. GAAP, except that Canadian GAAP allows for the presentation of operating cash flow before changes in non-cash working capital items in the consolidated statement of cash flows. This total cannot be presented under U.S. GAAP.

FAS 69 Supplemental Reserve Information (Unaudited)

The following data supplements oil and gas disclosure in the Trust's Annual Report, and is provided in accordance with the provisions of FAS 69.

Oil and Gas Reserves

Users of this information should be aware that the process of estimating quantities of "proved" and "proved developed" crude oil and natural gas reserves is very complex, requiring significant subjective decisions in the evaluation of all available geological, engineering and economic data for each reservoir. The data for a given reservoir may also change substantially over time as a result of the numerous factors including, but not limited to, additional development activity, evolving production history and continual reassessment of the viability of production under varying economic conditions. Consequently, material revisions to existing reserve estimates occur from time to time. Although every reasonable effort is made to ensure that reserve estimates reported represent the most accurate assessments possible, the significance of the subjective decisions required and variances in available data for various reservoirs make these estimates generally less precise than other estimates presented in connection with financial statement disclosures.

Proved oil and gas reserves are the estimated quantities of crude oil, natural gas and natural gas liquids which geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions.

Proved developed oil and gas reserves are reserves that can be expected to be recovered through existing wells with existing equipment and operating methods.

Canadian provincial royalties are determined based on a graduated percentage scale which varies with prices and production volumes. Canadian reserves, as presented on a net basis, assume prices and royalty rates in existence at the time the estimates were made, and the Trust's estimate of future production volumes. Future fluctuations in prices, production rates, or changes in political or regulatory environments could cause the Trust's share of future production from Canadian reserves to be materially different from that presented.

Subsequent to December 31, 2003, no major discovery or other favorable or adverse event is believed to have caused a material change in the estimates of proved or proved developed reserves as of that date.

Results of Oil and Gas Operations

(millions of Canadian dollars)	2003	2002	2001
Revenues	**$ 329.9**	$ 264.3	$ 306.5
Expenses			
Production costs	**79.4**	60.8	59.0
Depreciation, depletion and amortization	**170.3**	113.5	697.9
Accretion	**1.2**	–	–
Tax recovery	**(39.9)**	(26.0)	(217.1)
	211.0	148.3	539.8
Results of operations from oil and gas operations	**$ 118.9**	$ 116.0	$ (233.3)

Costs Incurred

(millions of Canadian dollars)	2003	2002	2001
Property acquisition costs			
Proved properties	**$ 202.4**	$ 57.7	$ 820.8
Unproved properties	**34.0**	5.7	6.8
Exploration costs	**5.7**	1.8	4.0
Development costs	**101.5**	56.8	71.3
	$ 343.6	$ 122.0	$ 902.9

Acquisition costs include costs incurred to purchase, lease, or otherwise acquire oil and gas properties.

Development costs include the costs of drilling and equipping development wells and facilities to extract, treat and gather and store oil and gas, along with an allocation of overhead.

There were no oil and gas property costs not being amortized in any of the years presented.

Capitalized Costs

(millions of Canadian dollars)	2003	2002	2001
Proved properties	**$ 2,189.0**	$ 1,838.8	$ 1,694.5
Unproved properties	**36.0**	44.2	55.7
	2,225.0	1,883.0	1,750.2
Less related accumulated depreciation, depletion and amortization	**(1,186.2)**	(1,011.6)	(901.9)
	$ 1,038.8	$ 871.4	$ 848.3

Proved Oil and Gas Reserve Quantities

	2003		2002		2001	
	Crude Oil & Natural Gas Liquids (mbbls)	Natural Gas (mmcf)	Crude Oil & Natural Gas Liquids (mbbls)	Natural Gas (mmcf)	Crude Oil & Natural Gas Liquids (mbbls)	Natural Gas (mmcf)
Opening balance	**25,989**	**279,106**	26,657	267,371	21,540	153,217
Revision of previous estimates	**225**	**(33,640)**	1,737	5,700	(1,264)	(20,442)
Purchase of reserves in place	**1,640**	**50,389**	954	18,929	11,536	160,184
Sale of reserves in place	**(28)**	**(803)**	(568)	(5,328)	(3,845)	(13,146)
Discoveries and extensions	**941**	**14,742**	736	25,337	2,360	15,449
Production	**(3,124)**	**(36,897)**	(3,527)	(32,903)	(3,670)	(27,891)
Closing Balance	**25,643**	**272,897**	25,989	279,106	26,657	267,371

Standardized Measure of Discounted Future Net Cash Flows Relating to Proved Reserves

The standardized measure for calculating the present value of future net cash flows from proved oil and gas reserves is based on current costs and prices and a 10% discount factor as prescribed by FASB 69.

Accordingly, the estimated future net cash inflows were computed by applying selling prices prevailing during the month of December to the estimated future production of proved reserves. Estimated future expenditures to be incurred in developing and producing proved reserves are based on average costs incurred in each year presented and assume the continuation of economic conditions existing at the end of each year presented.

Although these calculations have been prepared according to the standards described above, it should be emphasized that due to the number of assumptions and estimates required in the calculation, the amounts are not indicative of the amount of net revenue that the Trust expects to receive in future years. They are also not indicative of the current value or future earnings that may be realized from the production of proved reserves, nor should it be assumed that they represent the fair market value of the reserves or of the oil and gas properties.

Although the calculations are based on existing economic conditions at each year end, such economic conditions have changed and may continue to change significantly due to events such as the continuing changes in the natural gas market and changes in government policies and regulations. While the calculations are based on the Trust's understanding of the established FASB guidelines, there are numerous other equally valid assumptions under which these estimates could be made that would produce significantly different results.

Standardized Measure

(millions of Canadian dollars)	2003	2002	2001
Future cash inflows	$ 2,631.1	$ 2,890.5	$ 1,732.5
Future production costs	(804.9)	(699.0)	(642.5)
Future development costs	(69.4)	(73.4)	(38.7)
Other related future costs	(42.1)	(43.4)	(37.1)
Future net cash flows	1,714.7	2,074.7	1,014.2
Discount at 10%	(721.6)	(919.4)	(415.9)
Standardized measure of discounted future net cash flow related to proved reserves	$ 993.1	$ 1,155.3	$ 598.3

Summary of Changes in the Standardized Measure During the Year

Measure During the Year (millions of Canadian dollars)	2003	2002	2001
Sales of oil and gas produced, net of production costs	$ (255.0)	$ (203.5)	$ (247.3)
Net change in sales and transfer prices, net of development and production costs	(106.2)	672.6	(586.6)
Sales of reserves in place	(2.3)	(4.5)	(78.1)
Purchases of reserves in place	156.4	45.6	826.6
Extensions, discoveries and improved recovery, less related costs	48.5	52.3	101.7
Changes in timing of future net cash flows and other	(60.6)	(93.6)	(389.3)
Revisions of previous quantity estimates	(58.5)	28.3	(96.3)
Accretion of discount	115.5	59.8	97.1
Net change	(162.2)	557.0	(372.2)
Balance at beginning of year	1,155.3	598.3	970.5
Balance at end of year	$ 993.1	$ 1,155.3	$ 598.3

Supplemental Information

Five Year Financial Summary

($ millions, except per BOE and per Trust Unit amounts)	2003	2002	2001	2000	1999
Cash flow from operations	$ 216.6	$ 170.9	$ 214.5	$ 112.1	$ 41.1
Per Trust Unit	4.67	4.96	8.27	9.82	4.81
Per BOE	17.82	15.51	19.74	18.91	7.51
Net revenues	329.9	264.3	306.5	156.6	81.3
Per Trust Unit	7.12	7.67	11.81	13.72	9.51
per BOE	27.14	23.98	28.20	26.42	14.85
Operating expenses	79.4	60.8	59.0	30.2	28.6
Per Trust Unit	1.71	1.76	2.27	2.65	3.35
Per BOE	6.53	5.52	5.42	5.09	5.23
Operating margin	250.5	203.5	247.6	126.4	52.7
Per Trust Unit	5.41	5.90	9.54	11.08	6.16
Per BOE	20.61	18.46	22.78	21.33	9.62
Cash general and administrative expenses	14.5	11.3	10.4	4.1	5.3
Per Trust Unit	0.31	0.33	0.40	0.36	0.62
Per BOE	1.20	1.02	0.96	0.70	0.97
Interest expense	15.1	10.8	13.8	6.4	4.9
Per Trust Unit	0.32	0.32	0.53	0.56	0.57
Per BOE	1.24	0.98	1.27	1.07	0.89
Capital expenditures	104.5	64.2	83.9	25.8	14.2
Acquisitions net of dispositions	228.6	56.5	744.5	117.8	18.7
Working capital (deficit)	(5.8)	(0.7)	(29.4)	(0.3)	(5.9)
Total assets	1,679.9	1,502.5	1,522.3	441.6	320.2
Net asset value [1]	818.8	727.9	755.2	560.4	252.9
Per Trust Unit [1]	16.25	18.52	22.82	42.14	28.10
Total capitalization (including debt)	1,269.7	1,072.5	1,080.7	377.2	323.7
Debt Analysis					
Long-term debt, including working capital	255.9	225.7	224.4	78.8	85.3
Debt to annual cash flow ratio	1.18	1.32	1.05	0.71	2.10
Debt to equity ratio	25.1	26.6	26.2	26.6	46.1
Interest coverage ratio	15.9	16.9	16.5	18.6	8.5
Average cost of debt	4.7%	4.6%	5.4%	7.4%	5.9%
Net debt per Trust Unit	5.07	5.75	6.78	5.93	9.48
Tax pools (consolidated)					
Canadian oil and gas property expense (COGPE)	426.0	425.0	424.0	299.0	255.0
Canadian exploration expense (CEE)	61.5	–	23.7	5.7	–
Canadian development expense (CDE)	60.9	41.2	11.1	9.0	–
Capital cost allowance (CCA)	126.0	108.0	101.2	35.8	24.4
Losses available for carry forward	–	11.8	24.8	–	–
Unit issue expenses	17.3	12.5	12.2	6.2	8.3

[1] 2003 is based on February 5th Forward Strip pricing.

Five Year Operating Summary

	2003	2002	2001	2000	1999
Average daily production					
Natural gas (mmcf/day)	**134.1**	113.5	104.8	49.0	46.5
Crude oil (bbls/day)	**8,116**	9,239	10,033	6,582	5,958
Natural gas liquids (bbls/day)	**2,855**	2,030	2,273	1,483	1,293
Total (BOE/day)	**33,316**	30,189	29,774	16,237	14,995
Average selling prices (Cdn$)					
Natural gas ($/mcf)	**$ 6.05**	$ 4.55	$ 6.16	$ 4.65	$ 2.51
Crude oil ($/bbl)	**33.94**	33.53	32.21	36.67	21.69
Natural gas liquids ($/bbl)	**35.34**	26.56	30.96	34.42	19.09
Total ($/BOE)	**$ 35.68**	$ 29.16	$ 34.80	$ 32.19	$ 17.95
Benchmark prices					
Monthly AECO Spot (Cdn$/mcf)	**$ 6.70**	$ 4.07	$ 6.30	$ 5.02	$ 2.96
WTI (US$/bbl)	**$ 31.04**	$ 26.08	$ 25.97	$ 30.20	$ 19.24
Operating Margin ($/BOE)					
Revenues	**$ 35.52**	$ 29.11	$ 34.93	$ 32.28	$ 17.99
Royalties	**(8.38)**	(5.13)	(6.73)	(5.92)	(3.14)
Operating expenses	**(6.53)**	(5.52)	(5.42)	(5.09)	(5.23)
Operating margin ($/BOE)	**$ 20.61**	$ 18.46	$ 22.78	$ 21.27	$ 9.62
Reserves Summary[1,2]					
Crude oil (mmbbls)	**22.9**	24.5	28.5	24.4	20.0
Natural gas liquids (mmbbls)	**11.9**	10.2	9.5	6.4	6.1
Natural gas (Bcf)	**432.2**	418.5	413.7	232.7	224.0
Total barrel of oil equivalent (mmBOE)	**106.8**	104.4	107.0	69.6	63.7
Net Asset Value (millions of dollars, except per Trust Unit amounts)					
Reserves (10% discount)*	**$ 1,036.5**[3]	$ 923.0	$ 872.6	$ 623.0	$ 328.0
Hedging mark-to-market	**(6.0)**	(13.6)	50.5	(1.0)	–
Unproved lands and reclamation fund	**36.2**	44.2	56.5	17.2	10.2
Long-term debt and working capital deficiency	**(255.9)**	(225.7)	(224.4)	(78.8)	(85.3)
Total net asset value	**$ 818.8**	$ 727.9	$ 755.2	$ 560.4	$ 252.9
Per Trust Unit	**$ 16.25**	$ 18.52	$ 22.82	$ 42.14	$ 28.10
Reserve Life Index* (years)	**9.8**	9.5	10.0	10.2	10.9

(1) Company Interest reserves.
(2) Total Proved + Probable used for 2003, all prior years used established.
(3) Based on February 5th Forward Strip pricing.
* Established used from 1997-2002, Proved + Probable used in 2003.

Five Year Trading, Performance & Distribution Summary

		2003					2002	2001	2000	1999
		Q1	Q2	Q3	Q4	Full Year				
Units issued and outstanding										
Period end (000s)		43,668	44,172	47,821	48,752	48,752	37,005	31,492	12,746	8,942
Exchangeables issued and outstanding										
Period end (000s)		4,494	4,435	3,968	3,041	3,041	5,179	4,068	1,112	–
Converted to Trust Units		1,763	1,822	1,695	1,347	1,347	1,940	1,294	304	–
Exchange ratio at period end		0.39223	0.41070	0.42720	0.44302	0.44302	0.37454	0.31799	0.27333	–
TSX Unit price	High	$ 27.34	$ 27.76	$ 26.80	$ 28.15	$ 28.15	$ 29.56	$ 42.16	$ 37.20	$ 30.80
	Low	$ 24.48	$ 23.40	$ 25.19	$ 25.06	$ 23.40	$ 23.60	$ 23.80	$ 25.20	$ 19.00
	Close	$ 24.51	$ 25.04	$ 25.19	$ 27.56	$ 27.56	$ 25.40	$ 25.44	$ 35.80	$ 26.60
Average daily volume traded:		184,428	234,477	149,148	202,661	192,678	123,455	156,122	30,314	12,442
Market capitalization at end of period (Cdn$ millions)		$ 1,114	$ 1,152	$ 1,247	$ 1,381	$ 1,381	$ 989	$ 834	$ 467	$ 238
Total return for Canadian Unitholders during period		1.1%	7.0%	4.3%	13.4%	28.0%	19.5%	(5.8%)	75.7%	49.3%
NYSE Unit price	High	17.96	20.60	19.29	21.48	21.48	16.69			
	Low	16.05	15.97	18.08	18.67	15.97	15.62			
	Close	16.73	18.53	18.68	21.27	21.27	16.16			
Average daily volume traded:		111,605	166,722	151,813	243,921	169,269	39,276			
Total return for U.S. Unitholders during period		8.5%	16.0%	4.6%	18.0%	55.3%				
Distribution summary (Cdn$ millions, except per Trust Unit amounts)										
Cash distributed to Unitholders		$ 49.8	$ 52.8	$ 43.7	$ 46.3	$ 192.6	$ 158.0	$ 234.4	$ 79.0	$ 37.4
Per Trust Unit		$ 1.20	$ 1.20	$ 0.96	$ 0.96	$ 4.32	$ 4.80	$ 9.24	$ 7.08	$ 4.40
Percentage paid out		80%	97%	86%	107%	89%	92%	109%	70%	91%
Cumulative cash distributions						$ 771.5	$ 578.9	$ 420.9	$ 186.5	$ 107.5
Per Trust Unit						$ 40.24	$ 35.92	$ 31.12	$ 21.88	$ 14.80

Distribution History
($ per Trust Unit)

	2003		2002		2001		2000		1999	
Funds Paid In:	Cdn$	US$	Cdn$	US$	Cdn$	US$	Cdn$	US$	Cdn$	US$
Q1	$ 1.20	$ 0.79	$ 1.20	$ 0.75	$ 2.40	$ 1.56	$ 1.20	$ 0.82	$ 0.72	$ 0.48
Q2	1.20	0.87	1.20	0.77	2.56	1.66	1.32	0.89	0.88	0.60
Q3	1.04	0.75	1.20	0.77	2.64	1.71	1.92	1.29	1.24	0.84
Q4	0.96	0.72	1.20	0.76	2.04	1.31	2.24	1.46	1.40	0.94
Total for year	$ 4.40	$ 3.13	$ 4.80	$ 3.05	$ 9.64	$ 6.24	$ 6.68	$ 4.46	$ 4.24	$ 2.86
% Tax deferred	42%	100%	45%	100%	33%	N/A	47%	N/A	100%	N/A
Exchange rate (US$/Cdn$)	$ 0.715		$ 0.637		$ 0.646		$ 0.673		$ 0.675	

Income Tax Considerations

This commentary regarding income taxes is of a general nature only and is not intended to be legal or tax advice applicable to a specific Unitholder. Therefore, Unitholders are encouraged to consult a tax advisor with regard to their specific circumstances.

For Canadian Unitholders

PrimeWest is treated as a mutual fund trust for purposes of the Canadian Income Tax Act. Each year an income tax return is filed by the Trust with the taxable income allocated to, and taxable in the hands of Unitholders. Distributions paid by the Trust have two components: (1) a tax-deferred return of capital (i.e. a repayment of a portion of your investment) and (2) a return on capital (i.e. income).

Each year the return on capital or taxable portion of the distribution is reported on the Trust's T3 return. It is then allocated to each Unitholder who received distributions in the taxation year on the T3 supplementary forms, which are mailed in late February or early March of the following calendar year. Registered Unitholders receive a T3 from the Trust's transfer agent, ComputerShare Trust Company of Canada, while Unitholders who hold their units beneficially will receive a T3 from their bank or brokerage firm. The T3 form will indicate only the currently taxable portion, or other income, as it is regarded under Canadian tax law in box 26. This other income is taxed on the same basis as interest income. The tax deferred return of capital portion of the distribution should be treated as an adjustment to the cost base (ACB) of the units. On disposition, the cost base should be reduced by the accumulated value of returned capital, resulting in a capital gain or loss for tax purposes.

For 2003, 42% of the distribution paid to Canadian residents was deemed a tax-deferred return of capital, and 58% was deemed taxable as income. For tax year 2004, PrimeWest's Canadian distributions are estimated to be 60% taxable and 40% a tax-deferred return of capital.

For United States and Other Non-Resident Unitholders

Investors who do not qualify as residents of Canada for income tax purposes should seek advice from a qualified tax advisor in the country of residence regarding the tax treatment of the distributions. Monthly distributions payable to non-residents of Canada are normally subject to a withholding tax of 25% as prescribed by the Canadian Income Tax Act. However, the level of withholding tax may be reduced in accordance with reciprocal tax treaties.

In the case of the Canada – United States Tax Convention, U.S. residents are subject to a 15% withholding tax on the amount of the distributions. The 15% is refundable for the portion of the distributions deemed to be a tax-deferred return of capital.

U.S. residents may apply to the Canada Customs and Revenue Agency (CCRA) for this refund no later than two years after the calendar year in which the distributions were paid. U.S. investors can file CCRA Form NR7-R "Application for Refund of Non-Resident Tax" which is obtained by contacting the International Tax Services Office of the CCRA at 1-800-267-3395 or online at www.ccra.gc.ca.

Alternatively, U.S. Unitholders may elect to claim Canadian withholding taxes as a deduction against income or, subject to certain restrictions, as a credit against their U.S. tax liability. U.S. Unitholders wishing to claim a foreign tax credit must complete IRS Form 1116, Foreign Tax Credit, as an attachment to the Form 1040.

In the case of a U.S. Unitholder, the taxable portion of the monthly distribution is determined based upon current and accumulated earnings in accordance with the U.S. tax code. The currently taxable portion is regarded as "ordinary income – dividends" for tax reporting purposes and registered U.S. Unitholders should receive an NR-4 form from the Trust's transfer agent ComputerShare Trust Company of Canada. U.S. Unitholders who hold their units beneficially should receive a Form 1099-DIV or similar document from their bank or brokerage firm.

The tax deferred return of capital portion of the distribution should be treated as an adjustment to the cost base (ACB) of the units. The cost base should be reduced by this accumulated amount when computing gains or losses at the time of disposition, at which time this should be reported as a capital gain or loss.

Due to differences in the income tax code of the United States, certain deductions not available in Canada are available in the United States and could result in different distribution taxability breakdowns for U.S. Unitholders compared to those in Canada. For Unitholders resident in the United States, the taxability of distributions is derived using U.S. tax rules which permit the deduction of Crown royalties and accounting-based depletion.
As a result, none of the 2003 distribution is taxable as dividend, while 100% is a tax-deferred reduction to the cost base of the units. It is not expected that the 2004 tax situation will be materially different for U.S. Unitholders.

Premium Distribution, Distribution Reinvestment, and Optional Trust Unit Purchase Plan

PrimeWest offers a number of attractive and economical options for Unitholders to maximize their investment, including a Premium Distribution (PREP), Distribution Reinvestment (DRIP) and Optional Trust Unit Purchase Plan (OTUPP). Investors participate in these plans without paying fees, including brokerage commissions.

The DRIP allows eligible Canadian Unitholders to reinvest distributions into PrimeWest Trust Units purchased at a 5% discount to the volume weighted average market price. Alternatively, the PREP enables eligible Canadian Unitholders to receive a premium on their base cash distribution amount of up to 2%.

Additional Trust Units may be purchased by eligible Canadian Unitholders through the OTUPP in minimum amounts of $100 per remittance up to a maximum amount of $100,000 per calendar year, at a 5% discount to the volume weighted average market price. The number of units available under the OTUPP is limited by securities regulations to a maximum of 2% of the Trust Units outstanding at the end of the previous fiscal year.

Most larger banks, trust companies or brokerage firms will allow investors to participate in these programs, but many of the smaller firms do not. Please contact the bank, trust company or brokerage firm which holds your account to determine if they permit participation in these plans. If you are unable to participate as a beneficial holder, you will either need to hold the units directly as a registered Unitholder or transfer the units to a financial institution that permits participation.

If you are a registered Canadian Unitholder, we invite you to participate in these programs by completing the enrollment form on the PrimeWest Energy website at www.primewestenergy.com. If you hold your units in a bank or brokerage account, you will need to notify the appropriate bank or brokerage firm of your interest. Further information regarding the PREP, DRIP, and OTUPP can be obtained by contacting ComputerShare Trust Company of Canada (Plan Agent) toll-free at 1-800-564-6253, or the Investor Relations team at PrimeWest Energy toll-free at 1-877-968-7878, or via e-mail at investor@primewestenergy.com.

Abbreviations

bbls	barrels
mbbls	one thousand barrels
mmbbls	one million barrels
bbls/day	barrels per day
mcf	one thousand cubic feet
mmcf	one million cubic feet
mcf/day	one thousand cubic feet per day
Bcf	one billion cubic feet
m^3	one thousand cubic meters
BOE	barrels of oil equivalent
BOE/day	barrels of oil equivalent per day
mmBOE	millions of barrels of oil equivalent

Conversion Factors:

1 cubic meter (liquids) = 6.29 barrels

1 cubic meter (natural gas) = 35.49 cubic feet

1 litre = 0.22 imperial gallon

1 hectare = 2.47 acres

1 cubic meter = 1,000 litres

1 mcf of natural gas = 1.055 gigajoules of natural gas = 1 mmbtu

AECO
Refers to a pricing point for gas produced in Western Canada located at a gas storage facility adjacent to the TransCanada mainline near the Alberta-Saskatchewan border.

Barrel of Oil Equivalent (BOE)
Natural gas production is converted using six thousand cubic feet of gas for one barrel of oil, with this number added to the actual number of barrels of crude oil and natural gas liquids on an average day to derive the barrels of oil equivalent produced per day. BOEs may be misleading, particularly if used in isolation. The BOE conversion ratio is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.

Cash Distribution Date
The date Distributable Income is paid to Unitholders, currently being the 15th of each month, or the earlier business day if applicable, following any record date.

Declaration of Trust
Refers to the declaration of trust dated August 2, 1996 among the Trustee, PrimeWest, and the Initial Unitholder (as therein defined), as amended from time to time and administered.

Development Drilling
Drilling activity conducted in an area where production is already in place and where there is a high probability of finding additional oil and gas deposits.

Ex-distribution Date
The holder of units purchased prior to the ex-distribution date is entitled to the declared distribution paid on the 15th of the next month. Ex-distribution date is two business days prior to the record date.

Probable Reserves
Those additional Reserves that are less certain to be recovered than Proved Reserves. It is equally likely that the actual remaining quantities recovered will be greater or less than the sum of the estimated Proved plus Probable Reserves. In addition, the level of certainty targeted by the reporting company should result in at least a 50% probability that the quantities actually recovered will equal or exceed the sum of the estimated Proved plus Probable Reserves.

Proved Reserves
Reserves that can be estimated with a high degree of certainty to be recoverable. The reporting company must believe that there is at least a 90% probability that the actual remaining quantities recovered will equal or exceed those estimated Proved Reserves.

Record Date
The date by which a Unitholder must officially own the Trust Units in order to be entitled to receive a distribution.

Reserve Life Index
Is calculated by dividing the quantity of reserves by the total production of oil, natural gas, and natural gas liquids during the year.

Trustee
Refers to ComputerShare Trust Company of Canada, or its successor as trustee of the Trust.

West Texas Intermediate (WTI)
A high quality grade of crude oil produced in West Texas whose price is most commonly used as a benchmark for crude oil pricing internationally.

See PrimeWest's Renewal Annual Information Form for an explanation of additional defined terms used in this annual report.

Corporate Information

Board of Directors

Harold P. Milavsky,[1,2] *Chair*

Barry E. Emes[2]

Harold N. Kvisle[1,2]

Kent J. MacIntyre

Michael W. O'Brien[1,2]

James W. Patek[1,2]

W. Glen Russell[1,2]

[1] Member of the Audit and Reserves Committee and Compensation Committee

[2] Member of the Corporate Governance and Nominating Committee

Officers

Donald A. Garner
President and Chief Executive Officer

Ronald J. Ambrozy
Vice-President, Business Development

Dennis G. Feuchuk
Vice-President, Finance and Chief Financial Officer

Timothy S. Granger
Chief Operating Officer

Head Office

4700, 150-6 Avenue SW
Calgary, AB Canada T2P 3Y7
Telephone: 403-234-6600
Fax: 403-266-2825
Toll-free: 1-877-968-7878

Website

www.primewestenergy.com

Trust Units and Exchangeable Shares Traded

The Toronto Stock Exchange (PWI.UN; PWX)
The New York Stock Exchange (PWI)

Registrar and Transfer Agent

ComputerShare Trust Company of Canada
Toll-free in Canada:
1-800-564-6253

Auditor

PricewaterhouseCoopers LLP,
Calgary, Alberta

Engineering Consultants

Gilbert Laustsen Jung Associates Ltd.,
Calgary, Alberta

Legal Counsel

Stikeman Elliott LLP
Calgary, Alberta

For More Information

General inquiries: 403-234-6600

Investor Relations

Toll-free: 1-877-968-7878
Fax: 403-699-7269
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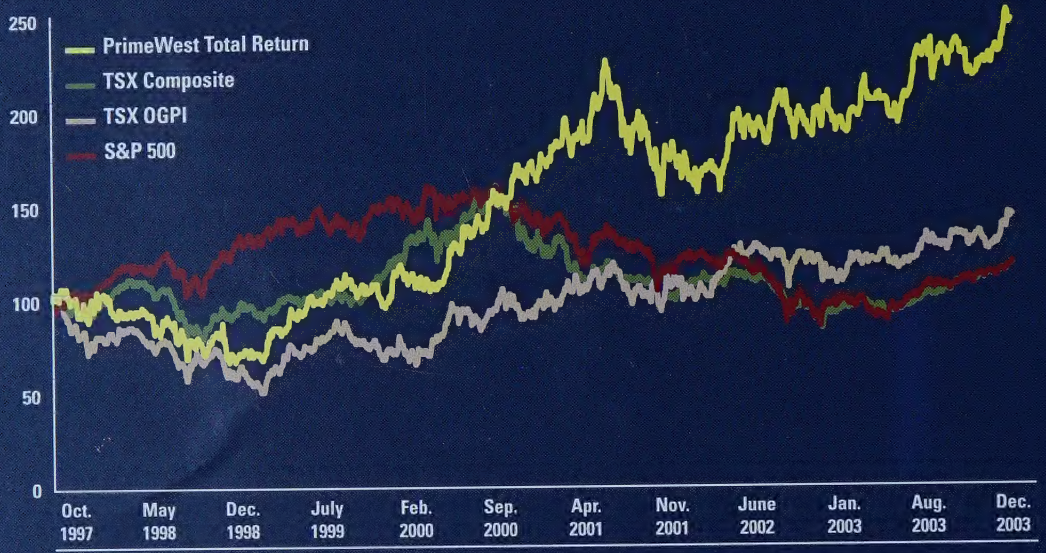
PrimeWest has achieved a competitive total return since inception.



Compound Total Return Comparisons (%)
Compound total return = unit price + distributions reinvested

PrimeWest Energy Trust
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